VERIFIED DIRECT TESTIMONY OF CHRISTOPHER KIERGAN

Q1. Please state your name, business address and job title.

A1. My name is Christopher Kiergan. I am employed by West Monroe Partners, LLC ("West Monroe") as a Senior Manager in the Energy and Utilities practice. My business address is 311 West Monroe Street, 14th Floor, Chicago, Illinois 60606.

Q2. On whose behalf are you testifying in this proceeding?

A2. I am testifying on behalf of Northern Indiana Public Service Company LLC ("NIPSCO" or "Company") in support of its investments in advanced technology for modernization of its transmission, distribution, or storage systems to deliver safe and reliable service, including deployment of advanced metering infrastructure ("AMI") (the "AMI Project") included in its Electric TDSIC Plan for the period June 1, 2021 through December 31, 2026 ("2021-2026 Electric Plan" or "Plan").

Q3. Please summarize your educational and employment background.

A3. A statement of my educational and employment background and qualifications is attached as Attachment 3-A.

Q4. Please describe your area of responsibilities as Senior Manager, Energy & Utilities as it relates to this proceeding?

A4. As a Senior Manager in the Energy and Utilities practice, I help utilities develop, plan, and execute strategies and projects for grid modernization to both optimize costs and benefits based on their unique operating conditions and enable utilities to establish a foundation for the transformation required for the modern utility to operate in the changing landscape and serve more-engaged customers. My team and I work with utilities across the United States on grid modernization cost benefit analyses, and I personally have worked on more than 15 utility modernization analyses over the past 12 years. These efforts have resulted in the refined approach used to quantify the benefits to customers, operations, and society for the Company's AMI Project. Additionally, my team and I have supported the implementation and execution of grid modernization programs similar to the AMI Project, leading to successful realization of the anticipated benefits. This end-to-end experience has informed West Monroe's approach to cost-benefit analysis and enabled our team to continuously refine inputs, calculation methodology, and accuracy.

Q5. Have you previously testified before the Indiana Utility Regulatory

Commission ("Commission") or any other regulatory commission?

A5. Yes. I have previously testified before the Commission in 2009, on behalf of Duke Energy Indiana, sponsoring and describing in detail the SmartGrid cost/benefit model that my team and I developed for Duke Energy. In addition, I testified before the Public Utility Commission of Ohio in 2008 on behalf of Duke Energy Ohio with regards to the cost benefit analysis underlying the AMI Proposal of their Electric Security Plan.

Q6. What is the purpose of your direct testimony in this proceeding?

A6. West Monroe has worked with the Company to complete a comprehensive cost-benefits analysis ("CBA") for the Electric AMI Project. The detailed results of the CBA are attached hereto as <u>Attachment 3-B</u> (the "CBA Results"). The purpose of my testimony is to describe the general process in developing the CBA, explain the structure of the CBA, highlight the cost and benefit inputs and other information provided to West Monroe by the Company, and to support and explain certain Company, customer, and societal benefits that I calculated that are associated with the AMI Project. I also summarize the results of the CBA and provide relevant industry perspective and context regarding the AMI Project.

Q7. Are you sponsoring any attachments to your direct testimony?

A7. Yes. I am sponsoring the following attachments, all of which were prepared by me or under my direction and supervision.

Attachment 3-A	Educational and Employment Background and Qualifications
Attachment 3-B	AMI Project Cost-Benefit Analysis – Detailed Results[1]
Attachment 3-C	AMI Obsolescence White Paper

INTRODUCTION TO AMI

Q8. What is your perspective on AMI adoption in the broader electric utility industry?

A8. Over the last several years, AMI has continued to grow as the standard for electric utilities and as a preferred technology when compared to advanced meter reading ("AMR") meters. While the initial switch from manually read meters to drive-by AMR meters enabled meter reading process efficiencies, several factors are driving utilities to pursue AMI. For example, AMR meters are not equipped with remote service connect/disconnect switches (requiring these service orders to continue to

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[1] A detailed discussion of the AMI Project is included in Section 6.2 and Confidential Appendix C to the 2021-2026 TDSIC Investment Plan Cost Analysis dated May 2021 prepared for NIPSCO by Sargent & Lundy sponsored by Witness Vamos as Confidential Attachment 2-C.

be performed manually), do not provide interval energy usage data or demand readings (which enable time of use and other rate options), and lack visibility into near real-time operational conditions (which enable insights into outage awareness, voltage sags and swells, meter temperatures, and meter tampering that could indicate theft). On the other hand, AMI meters provide this breadth of functionality and enable further outcomes such as improved load forecasting and power quality management which is increasingly necessary given the growing complexity of two-way power flow on the grid as Distributed Energy Resources ("DERs") are adopted and encouraged in the market.

Q9. Has West Monroe looked at overall AMI adoption? If so, please explain adoption rates in the United States.

A9. Yes. West Monroe has analyzed overall AMI adoption rates in the United States. According to the US Energy Information Administration ("EIA"),[2] AMI adoption, at the end of 2019, has reached 94.8 million meters or 60.3% of all installed meters in the United States. The adoption rates for several

[2] AMI adoption data from 2019 Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files (Advanced_Meters_2019) published by the US Energy Information Administration.

sub-categories associated with NIPSCO are consistent with this overall adoption rate, including:

Figure 1. AMI Adoption Rates[3]

Geographical Area	Electric AMI Adoption Rate
Indiana (all utilities)	54.1%
Region (all utilities) (IA, IL, IN, KY, MI, MO, OH, TN, WI)	64.0%
MISO Central/North (all utilities)	58.7%
Nation (IOUs only)	60.7%
MISO Central/North (IOUs only)	58.1%

Additionally, the growth rate of AMI has been consistent over the last five years as the number of installed AMI meters in the US has grown annually at a rate between 9% and 14%. Estimates, based on AMI deployments currently underway, projected a continued 9% growth in 2020, with the total AMI meters installed reaching 107 million meters and percent adoption hitting approximately 68.0%.[4]

This demonstrates that AMI continues to progress with more electric

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[3] *Id*.

[4] Number of Electric Smart Meter Installations Deployed in the U.S. from 2007-2020, Statista, Energy and Environment. See https://www.statista.com/statistics/676472/number-of-smart-meter-installations-in-the-united-states/#:~:text=Number%20of%20smart%20meter%20installations%20in%20the%20U.S.%202007%2D2020&text=This%20statistic%20shows%20the%20number,installed%20in%20the%20United%20States..

utilities adopting this technology each year and multiple utility deployments in progress. As discussed below, this is not surprising, as there are a wide range of benefits associated with implementation of AMI meters.

Q10. Please explain any broader policy and/or technology changes that are also pushing electric utilities to adopt AMI technology.

A10. In addition to enhanced customer experience and operational efficiency benefits associated with AMI, there are additional policy and technology changes that are driving utilities to install AMI as a foundational technology for the modern utility. These changes include:

- Distribution Automation ("DA") – As part of TDSIC in Indiana, and at utilities across the country, utilities are deploying digital monitoring and control equipment on their distribution systems.[5] This DA equipment, with both embedded intelligence and monitoring and control by distribution management systems, enables the distribution system to operate more efficiently and limits the impact of outages. AMI meters and systems can provide valuable usage, load, and voltage information to improve distribution management operations and enable/enhance functionality such as Volt-VAR Optimization ("VVO").

- Electric Vehicles ("EV") – As electric vehicles become more mainstream across the United States, electric utilities, including

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[5] As discussed by Witness Vamos, NIPSCO is proposing Distribution Automation and Substation Automation Projects as part of its 2021-2026 Electric Plan.

utilities in Indiana, are joining together in consortiums and coalitions (e.g., Midwest Regional Charging Network, Electric Highway Coalition) to coordinate EV charging efforts. As public EV charging stations become more commonplace, EV adoption will expand. As EV ownership expands, more at-home charging stations will be installed. In order to understand and respond to the impact of EV charging on the distribution system, and to offer residential EV charging programs, AMI meters will be required.

- Distributed Energy Resources (DER) – As the installed base of residential DERs and associated smart inverters expands, real-time control and monitoring will be required to ensure distribution grid stability. A component of this monitoring and control will be usage, load, and flow data that can be provided by AMI. Although DER proliferation in Indiana is not guaranteed, FERC Order No. 2222[6] and MISO's positioning with respect to solar power will likely drive the installation of DERs.

- Empowering Customers – Whether it be customers looking for enhanced programs and more usage data from their utilities or regulators guiding utilities to become more customer-centric, utilities are responding with a renewed focus on the customer. NIPSCO wants to be positioned to consider offering advanced programs to customers, and, in order to do so, it is often necessary for the distribution utility to have interval usage data and two-way communications to a meter with remote capabilities, both capabilities provided by AMI.

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6 FERC Order No. 2222 enables the aggregation of DERs as small as 10 kW generators into the Midcontinent Independent System Operator, Inc. ("MISO") market while also addressing the data needs of regional transmission organizations ("RTOs") and independent system operators ("ISOs"); data needs that can be supported by AMI. Order No. 222, 172 FERC ¶ 61,197 (2020). "The Commission recognized that RTOs/ISOs need metering data for settlement purposes and telemetry data to determine a resource's real-time operational capabilities so that they can efficiently dispatch resources." (*Id.* at p. 187). "Further, as noted in Section IV.G, to the extent that metering and telemetry data comes from or flows through distribution utilities, we require that RTOs/ISOs coordinate with distribution utilities and the relevant electric retail regulatory authorities to establish protocols for sharing metering and telemetry data that minimize costs and other burdens and address concerns raised with respect to customer privacy and cybersecurity." (*Id.* at p. 246)

Q11. With the recent proliferation of cyber-attacks on utilities, is AMI protected against these types of intrusions?

A11. Yes. Modern AMI technology solutions comply with existing utility cyber security procedures for the purpose of protecting sensitive customer and utility information, as well as for safely and reliably operating the grid. Regarding customer and utility information, all usage data collected and transmitted over an AMI network is typically encrypted to prevent data from being accessed or corrupted via an attempted cyber-attack. Regarding maintaining grid operations, AMI meter and network communication devices are designed to be resistant to cyber threats. Over the years, AMI vendors have continually strengthened the security of both the device hardware and the associated software while also increasing the security of their data centers, where the AMI Headend software application typically resides.[7] Additionally, AMI systems typically operate in isolation from real-time utility distribution and transmission systems, with several layers of additional cyber security in place.

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[7] Headend software enables the utility to monitor and control both meters and communications assets.

<u>CBA RESULTS AND PROCESS SUMMARY</u>

Q12. Before you discuss the process for developing the CBA, what are the results of the CBA for NIPSCO's planned AMI Project?

A12. Figure 2 below illustrates the projected benefits, costs, and net costs and benefits in nominal terms of NIPSCO's AMI Project.

Figure 2. Cost/Benefit Summary (in Millions)[8]

Cost and Benefit Categories	Category Components	Deployment Totals (2021-2026)	Average Annual Post Deployment (2027-2036)	Post Deployment Totals (2027-2036)	Program Totals (2021-2036)
Capital Cost (Indirect)	Corporate Overhead, AFUDC	-$22.19	-$0.06	-$0.61	-$22.81
Capital Cost (Direct)	AMI Meters and Installation, AMI Communications Network Equipment and Installation, AMI Replacements, MDMS and Other System Integrations, Cyber Security, Project Management, AMI IT, AMI Ops, Change Management / Business Readiness, Contingency, Materials Tax	-$145.47	-$0.43	-$4.33	-$149.81
O&M Cost (One-Time Expense)	Customer Engagement, Project Management, Change Management / Business Readiness	-$10.01	$0.00	$0.00	-$10.01
O&M Cost (Recurring)	AMI IT, AMI Ops, AMI Replacement Labor, AMI Communications Fees and Warranties, MDMS and Other System Maintenance	-$11.81	-$5.80	-$58.04	-$69.86
O&M and Expense Reduction Benefit	Meter Reading, Meter Servicing, Outage Management, AMR Software and Licensing, Residential and Commercial AMR Meter Replacement, Bad Debt	$12.43	$15.25	$152.46	$164.89
Avoided Capital Benefit	Vehicle Purchase, AMR Collector Hardware, Replaced AMR Meters	$0.94	$0.79	$7.89	$8.83
NIPSCO Cost of Service Reduction Benefit	Theft, Consumption on Inactive Meters	$3.00	$3.01	$30.10	$33.10
Customer Benefit	Customer Electric DSM Benefit (Residential), Customer Reliability Improvement (Residential, Commercial, Industrial)	$7.97	$9.07	$90.75	$98.72
Net Costs and Benefits (Nominal)	Net of the above categories	-$165.15	$21.82	$218.21	$53.06

As demonstrated in Figure 2, the benefits of the AMI Project exceed the costs over a 15-year horizon. The CBA thus represents a positive business case from a financial perspective, providing over $300 million in benefits,

8 CBA Results, Page 22.

which represents net benefits of approximately $53 million on a nominal basis.

In addition to these quantitative benefits, there are additional qualitative benefits associated with improving the customer experience, enabling future customer and utility operations programs, reducing greenhouse gas ("GHG") emissions associated with reducing truck rolls and drive-by meter reading (quantified, but not included in the CBA Results), and increased safety. The AMI Project also provides a societal economic and jobs benefit which has been incorporated into the overall calculation of jobs created by the 2021-2026 Electric Plan.

Q13. What methodology did West Monroe employ in completing the CBA?

A13. West Monroe utilized its proprietary AMI CBA tool, a detailed Microsoft Excel spreadsheet analytical model created and managed by West Monroe. This model, capable of complex calculations and sensitivity analyses, has been continuously refined in terms of calculation methodology and specific benchmark inputs through its use at multiple utilities. Additionally, the CBA was tailored for NIPSCO parameters, including the application of allowance for funds used during construction ("AFUDC"), contingency, corporate overhead, materials tax, and labor inflation to only specific cost categories and cost elements.

West Monroe leveraged an established methodology for valuation of the projected costs and benefits for large grid transformation projects. In general, the methodology incorporated both inputs from NIPSCO and, in areas where NIPSCO had less experience, inputs from West Monroe benchmarking data derived from several recent AMI business case analyses. In terms of costs in the CBA, West Monroe coordinated with NIPSCO to capture and input capital and operations and maintenance ("O&M") expenses associated with delivering the AMI Project, including internal and external labor, equipment, software, hardware, and services. For each cost component, NIPSCO provided cost data inputs, unit costs, assumptions, and other information. West Monroe, however, benchmarked the cost inputs based on industry experience and perspective from similar efforts. The benchmarking process helped balance scope and investment to match anticipated benefits based on the experience of other utilities. Because NIPSCO is just initiating the AMI Project, it did not have vendor-supplied cost information for certain components. For these components, including AMI meter costs, AMI communication asset costs, and a Meter Data Management System ("MDMS"), West Monroe used benchmark data from several recent AMI business cases and deployments to estimate the scope needed and the corresponding costs. The cost information served as one input to the CBA, which also considers projected annual costs and ongoing operational impacts, and applies inflation and other escalation factors, as appropriate.

As for the benefits calculations, the nature and value of the customer benefits from the AMI Project have been provided by NIPSCO and evaluated by West Monroe based on our experience and industry benchmarks. The CBA Results provides a summary of the categories of benefits included in the CBA. In line with the TDSIC Statute,[9] the AMI Project is undertaken for the purposes of modernizing NIPSCO's system and improving safety and reliability. From a qualitative perspective, benefits can be thought of as satisfying four primary goals: (1) Enhancing the Customer Experience, (2) Improving Safety and Reliability, (3) Improving Operating Efficiencies, and (4) Unlocking the Potential for

[9] Ind. Code Ch. 8-1-39 (Transmission, Distribution, and Storage System Improvement Charges and Deferrals) was enacted as part of Senate Enrolled Act 560 and became effective on April 30, 2013, which was amended in House Enrolled Act No. 1470 and became effective on April 24, 2019 (the "TDSIC Statute").

Further Utility Transformation. When specifically focusing on the quantitative benefits calculated in the CBA, at a summary-level, the benefits are categorized as (1) O&M and Expense Reduction, (2) Avoided Capital, (3) NIPSCO Cost of Service Reduction, and (4) Customer. An overview of the cost and benefit calculations is provided in the CBA Results.

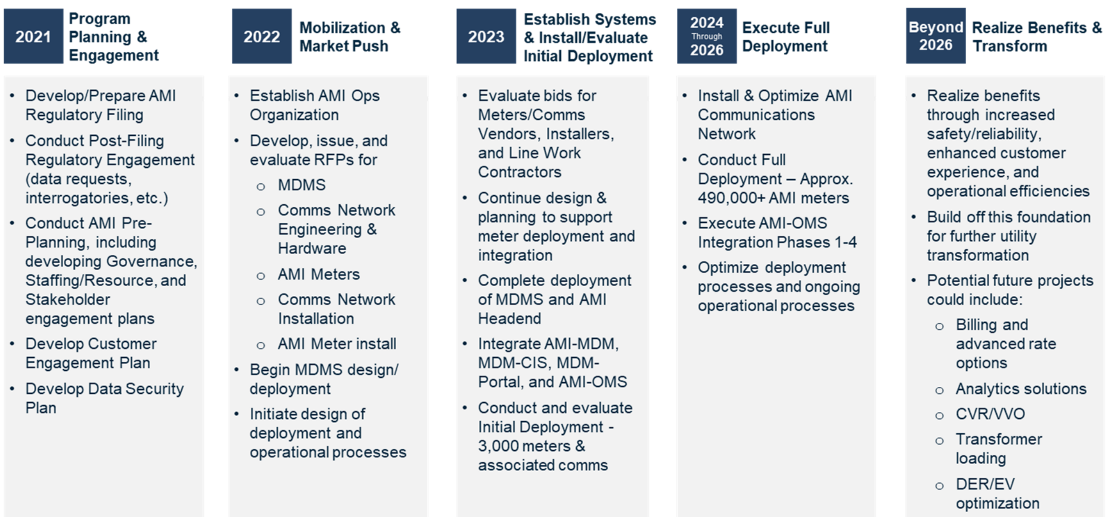
Q14. Over what period of time are the deployment costs projected to be incurred?

A14. Deployment costs associated with the AMI Project, including both capital costs and one-time O&M expenses, are scheduled to be incurred during the 6-year period of 2021-2026.

Q15. Can you describe the timeline of activities associated with the 6-year deployment of the AMI Project?

A15. After pre-planning and regulatory engagement in 2021, 2022 would consist of detailed planning, issuance of request for proposals, and major decisions around the AMI system and information technology ("IT") systems required in the AMI Project. In 2023, the required IT systems and integrations would be deployed and an initial deployment of an estimated 3,000 meters would be executed and evaluated to test and optimize deployment and operational processes ("Initial Deployment"). Full deployment of almost 500,000 meters would then be conducted during 2024-2026. A more detailed listing of activities appears in Figure 3 below:

Figure 3. Summary Timeline of Activities[10]



Q16. What is the purpose of this Initial Deployment?

A16. In the past, when technologies themselves were still being evaluated, a utility would execute a pilot program to understand the technology and evaluate its applicability to the utility's operations and needs. In the case of AMI, the technology has been proven through successful deployments to over 60% of the electric meters throughout the United States, and a pilot

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10 2021-2026 NIPSCO Electric AMI Business Case prepared by West Monroe (the "AMI Business Case") (Confidential Attachment 2-B, Appendix C to Witness Vamos' direct testimony), Page C-8.

is not necessary. Although a proven technology, AMI deployment at NIPSCO will still require tailored deployment processes, unique integrations between new and existing IT and Operations Technology (or OT) systems, and a method of testing and refining processes ranging from supply logistics to meter and communication asset deployment to meter activation in the AMI Headend System and MDMS to moving data from the meters to, ultimately, billing systems. The Initial Deployment will consist of 3,000 meters and associated communications modules. Lasting six months in 2023, this Initial Deployment will be used to test, refine, and optimize all deployment processes and to test and optimize end-to-end data flow from the meters to the AMI Headend System and MDMS and then ultimately to billing, outage management, and customer portal applications. At the end of the Initial Deployment, NIPSCO will be prepared to undertake full deployment, provide full functionality as each meter is deployed, and realize the associated benefits as deployment progresses.

Q17. Over what period of time are the benefits projected to be delivered to customers?

A17. Benefit realization for customers will begin as soon as the AMI Project meter deployment begins in 2024 and will continue to be delivered for many years to follow. With the associated IT systems and integrations in place prior to meter deployment, as an AMI meter is installed on a customer's premises, the functionality driving benefits is operational. The CBA accounts for deployment dates and a 15-year horizon. In other words, once an asset is deployed, the benefit stream tied to it is projected to be realized only from that starting point through 2036, the ending point of the 15-year CBA.[11] The CBA Results provides a Deployment Timeline Summary for the AMI Project components. Attachment 3-A, Page 5.

Q18. Please further describe the role that West Monroe played in the calculation of these benefits within the CBA?

A18. For each scope area, West Monroe facilitated working group workshops with NIPSCO to identify the specific inputs and data points that would be needed to project the calculation of benefits. In some cases, the benefit values were provided directly to West Monroe and input into the analysis without modification. In other cases, information was provided and

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[11] While 15 years is longer than the period covered by the 2021-2026 Electric Plan, this is a potentially conservative approach, as benefits will continue to be realized throughout the entire useful life of the AMI Project assets, which will in many cases be well over 15 years.

additional work was undertaken using established tools, relevant industry knowledge and experience, benchmarking, and other analyses to complete the projection of benefits and incorporate them into the CBA. It should be noted that the overall benefit projections assume that all elements of the AMI Project will be approved.

Q19. Has this methodology used for the CBA been leveraged for similar utility investments in other jurisdictions?

A19. Yes. The West Monroe CBA has been leveraged by many utilities over the last ten plus years. This includes as a key component of Department of Energy ("DOE") Grant Applications that were selected for award, formal utility modernization approvals for municipalities across the United States, formal grid modernization hearings for investor owned utilities in Massachusetts, Ohio, Virginia, and California, and multiple internal prudency and benefit cost reviews by utilities across the country.

Q20. Please provide a summary of the investments that are included in the CBA.

A20. Detailed annual cost information for the AMI Project as pertinent to the CBA is provided in the CBA Results. The West Monroe CBA calculates costs in terms of capital costs and one-time O&M expenses associated with the deployment of the AMI Project during 2021-2026.

Capital costs during AMI Project deployment are divided between direct and indirect costs.[12] Direct capital costs are calculated to be $145.5 million and are comprised of the following primary components:[13]

- AMI meters – The meters that are installed at residential, commercial, and industrial premises, including the installation labor.
- AMI communications network – The communication assets located in the field that provide two-way communications between the AMI Headend System and the meters, including relaying usage, alarm, and event information from the meters to the AMI Headend System and transmitting control signals (remote connect/disconnect, on-demand read) to the meters. These costs include engineering, design, materials, installation, and network optimization.
- MDMS – The on-site software package that receives interval usage information from the AMI Headend System, calculates billing determinants, and provides these determinants to the existing NIPSCO billing system. Costs include hardware, software, and labor.
- AMI Headend System – The software package that enables the utility to monitor and control both meters and communication assets. Typically housed within vendor's data center and provided to the

[12] Indirect capital costs for the AMI Project, comprised of Overhead and AFUDC, are calculated in the BCA to be $22.2 million. CBA Results, p. 4. These costs are used in the evaluation of the BCA for the AMI Project but are included in budgeted indirect costs reported for the overall Plan portfolio.

[13] CBA Results, p. 4.

utility in a software-as-a-service (SaaS) model.

- Other IT – Cybersecurity components and integrations both among the MDMS and the AMI Headend System and between these two systems and other NIPSCO systems, including billing, outage management, and customer portal. Costs include hardware, software, and labor.
- Project Management – Labor costs to plan, manage, track, and report on the AMI Project from 2021-2026.
- Change Management/Business Readiness – Labor costs to develop all specific AMI Project deployment processes.
- Materials Taxes – Tax on materials and hardware.
- Contingency – Consistent with other TDSIC projects included in the Plan, the AMI Project also includes contingency.[14]

One-time O&M expenses during deployment of the AMI Project (2021-2026) are calculated to be $10.0 million. Primary activities that drive these expenses are:

- Customer engagement with respect to the impact and benefits of AMI and specific AMI deployment information.
- Project management and change management / business readiness associated with developing AMI operational processes.

Q21. Can you expand on the cyber security costs mentioned above?

A21. With the addition of hundreds of thousands of communicating devices to the NIPSCO service territory, cyber security solutions for AMI that

[14] Witness Vamos provides a discussion of and justification for inclusion of contingency.

complement those provided by AMI meter vendors and the communications network provider will mitigate risks to NIPSCO. Costs for these cyber security solutions are comprised of hardware/software costs for systems capable of performing firewall management, access and authorization/authentication, active directory validation, vulnerability scanning, and file integrity monitoring, plus associated internal labor during design and deployment of these solutions. Furthermore, planned penetration testing accounts for a portion of the costs.

Q22. Are there any recurring O&M expenses associated with the AMI Project?

A22. As part of the CBA, recurring O&M expenses are calculated and included in the overall analysis of costs and benefits associated with the AMI Project, as reflected in Figure 2 above. However, these expenses have been excluded from this filing as NIPSCO is not seeking recovery of recurring O&M expenses through the TDSIC. Recurring O&M expenses will be addressed through normal rate making processes.

QUANTIFIED BENEFITS

Q23. Please describe the quantified benefits.

A23. Quantified benefits in the CBA are divided into four categories: (1) O&M and Expense Reduction, (2) Avoided Capital, (3) NIPSCO Cost of Service

Reduction, and (4) Customer.

(1) <u>O&M and Expense Reduction Benefit</u>

Q24. Please explain how the benefits associated with total O&M expense savings as presented in the CBA were derived.

A24. West Monroe worked with NIPSCO to identify areas of O&M expenses that would be eliminated or reduced as a result of investments within the scope of the AMI Project. This analysis was based on NIPSCO's operating history and existing budgets if the AMI Project were not to move forward. NIPSCO provided these O&M expense savings details for areas such as AMR meter reading and meter servicing costs, AMR and meter servicing vehicle costs, avoided truck rolls associated with "found-on" events, improvements in outage locating, and other operational improvements. As noted in Figure 2 above, the total benefits associated with O&M expense savings are approximately $164.9 million over the next 15 years. The CBA details regarding each benefit in this category and annual benefit values is provided in the CBA Results (pp. 15-18).

(2) <u>Avoided Capital Benefit</u>

Q25. Please explain how the benefits associated with total avoided/deferred capital as presented in the CBA were derived.

A25. West Monroe worked with NIPSCO to identify the previously planned investments that would be avoided or deferred as a result of investments within the scope of the AMI Project. This analysis was based on NIPSCO's operating history and previously existing plans if the AMI Project were not to move forward. NIPSCO provided details for a wide range of investment types that would be avoided or deferred, including purchases of AMR meters and collectors, AMR IT systems, and meter reading vehicles. As noted in Figure 1 above, the total benefits associated with avoided/deferred capital are approximately $8.8 million over the next 15 years. The CBA details regarding each benefit in this category and annual benefit values is provided in the CBA Results (p. 14-15).

(3) Cost of Service Reduction Benefit

Q26. Please explain how the benefits associated with total reduction of cost of service as presented in the CBA were derived.

A26. West Monroe worked with NIPSCO to identify the current and projected levels of energy diversion or theft associated with meter tampering and the current levels of consumption on inactive meters. By leveraging the functionality of AMI, specifically the use of the remote connect and disconnect switch, and the ability to identify meter tampering activities or malfunctioning equipment more accurately, utilities across the Country have experienced significant reductions in energy diversion and consumption on meters for which an account is in an inactive status. Projected savings for NIPSCO were based on similar programs and technology deployments, and as noted in Figure 2 above, the total benefits associated with energy diversion and consumption on inactive meters are approximately $33.1 million over the next 15 years. The CBA details regarding each benefit in this category and annual benefit values is provided in the CBA Results (p. 15).

(4) <u>Customer Benefit</u>

Q27. Please explain the components of the Customer Benefits category and how these benefits as presented in the CBA were derived.

A27. The Customer Benefit category is defined as those benefits that have an impact on customer spend and are comprised of two components: Customer Electric Demand Side Management ("DSM") Benefits and Customer Reliability Improvement.

<u>Customer Electric DSM Benefits</u>

NIPSCO plans to deploy AMI and a modernized Customer Portal that includes enablement of advanced channels of communication with customers.[15] Among the information that will be accessible to customers via the Customer Portal is the presentation of the interval energy usage data that is made available via AMI. Research has shown that customers with AMI meters and enhanced customer portals reduce their energy consumption. The benefit calculation incorporates the percentage of customers that are expected to actively engage with and leverage the additional information, as well as the percentage of energy usage that will be reduced as a result of that engagement and change in behavior. Within the CBA, it is estimated that 10% of customers will be actively engaged and adjusting their behavior, and that the impact of that will be a 1.1% reduction in energy usage for those customers in the steady state, following AMI and the Customer Portal deployment.

<u>Customer Reliability Improvement Benefits</u>

There are several sources of the reliability improvements in the overall Plan described by Witness Vamos, including a reduction in the number of customer interruptions resulting from DA projects. There will be additional impacts on outages resulting from AMI deployment, but these

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[15] The Customer Portal modernization is a separate initiative outside of TDSIC.

impacts will be seen in a reduction in the duration of the outages or in the customer minutes of interruption. With AMI providing more complete information on customers impacted by an outage, or remaining out after initial restoration work is completed, NIPSCO is able to pinpoint the location of the outage more quickly, resulting in a decrease in the overall duration of the event. In this area of improvement, NIPSCO provided projections regarding the percentage of total outage time spent locating outages and the relative amount of improvement that could be realized.

West Monroe then input NIPSCO's company-specific information into the United States DOE Interruption Cost Estimate ("ICE"), version March 2018, to calculate the value of the improved reliability benefits to customers in dollar form. The resulting calculation captured the benefits from AMI-related reliability improvement by year in the CBA and were included in the CBA based on the timing of planned AMI Project investments and the asset life of the related assets that drive the benefit.

As noted in Figure 2 above, the total benefits associated with the Customer Benefit category are estimated to be approximately $98.7 million over the next 15 years. The CBA details regarding each benefit in this category and annual benefit values is provided in the CBA Results (pp. 18-19).

Q28. Is the DOE ICE model a reasonable method for quantifying reliability benefits?

A28. Yes. Lawrence Berkeley National Laboratory created the model for the DOE as a means to identify the value of service reliability for electricity customers in the United States. The DOE ICE Calculator quantifies the economic benefit from improvements in system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI") to key customer segments for utilities based on their size and region in a consistent and transparent fashion. The DOE ICE Calculator is accepted in the industry as a dependable source for reliability benefit valuation and has gone through several iterations since first being introduced about a decade ago, including the latest update in March 2018.

The 2018 version of the DOE ICE Calculator has been updated to improve the accuracy of the reliability calculations by also taking into consideration the state gross domestic product ("GDP"). The researchers have found that the higher the state GDP, the more important electric reliability is to the customers, especially for businesses. Additional information on the model and the calculation methods used to correlate reliability improvements to customer economic impacts can be found at www.icecalculator.com.

Many utilities have used the DOE ICE Calculator to translate specific customer reliability improvements in the form of SAIDI and SAIFI to customer financial benefits, which are found in technical literature, industry conference presentations, and utility fillings.

Q29. Did you take a conservative approach to many of the benefits assumptions used to complete the CBA?

A29. Yes. There are several reasons why it is more appropriate and prudent to conservatively estimate benefit components of the CBA. First, many of the planned investments within AMI Project are foundational by nature, and not yet installed. Because of this, and given the unique nature of any company's service territory, it is appropriate to take a measured approach to projecting elements of the analysis that drive certain benefits, particularly those associated with customer behavior and program adoption. For this reason, a blend of industry benchmarking and Company history with customer programs was used to develop certain benefit projections.

<u>ADDITIONAL AMI PROJECT BENEFITS</u>

Q30. Please explain why certain benefits were not included in the "total" for the baseline CBA calculation, and are instead listed as "societal."

A30. While West Monroe and NIPSCO are confident the AMI Project will produce some level of societal benefits, it was deemed appropriate not to monetize these benefits and to exclude them from the baseline cost-benefit comparison to provide a customer-focused assessment of the planned investments. Again, for reference, the societal benefits include a reduction in GHG emissions and overall economic impact of the planned investments.

Q31. What work was done to project GHG reduction benefits associated with AMI Project investments?

A31. The projects that reduce the consumption of electricity, as described and quantified above, also result in lower emissions due to the reduction in electricity generation. Deploying AMI reduces vehicle miles associated with meter reading and decreases the number of found-on response events, which in turn reduces the amount of GHG created by vehicles. Two separate calculations were made to capture the reduction in greenhouse gas emissions: (1) reduced miles travelled in gasoline/diesel vehicles, and (2) impact due to reduced megawatt hour ("MWh") of electricity generation.

NIPSCO provided inputs and data points to West Monroe to then calculate these GHG reductions.

- Avoided Vehicle Emissions – The deployment of AMI meters results in a reduction in fleet requirements, both for AMR meter reading that is eliminated and for a wide range of orders executed by the field services function. The reduction of carbon dioxide ("CO_2") emissions that occurs from fewer truck miles was then calculated based on reduced vehicle mileage, the fuel economy of a representative truck per mile, and the carbon intensity of the fuel.
- Avoided Power Plant Emissions – The CBA modeled that customer utilization of the customer portal would result in marginal energy savings after AMI deployment. This would equate to an estimated MWh reduction level and, based on an EIA metric for tons of CO_2 produced per MWh of electricity generated in the state of Indiana, this this would reduce electric sector emissions in the state of Indiana by an estimated CO_2 tonnage.

Using benchmarks for the cost of CO_2, the reduction in GHG emissions is estimated to provide $5.2 million in benefits. CBA Results, p. 20.

Q32. What method was used to calculate the economic impact of the AMI Project investments?

A32. NIPSCO worked with West Monroe to develop the projected impact of the AMI Project on the economy, including creation of jobs and overall stimulus. The AMI Project inputs were combined with inputs from the other components of TDSIC investment. Total TDSIC impact on the economy was then calculated using IMPLAN, an economic impact assessment software system.[16] The IMPLAN software was subsequently run using just the AMI investment inputs, resulting in estimated economic impact to the state of Indiana of $260.62 million (Direct Effect) to $490.21 million (Total Effect). Looking at the impact of AMI Project investment at a national level, IMPLAN estimates an economic impact of $323.40 million (Direct Effect) to $1,303.41 million (Total Effect).

Q33. Are there further benefits that are not easily quantified in terms of economic value?

A33. Yes. One prime example is the significant improvement to the customer experience that will be delivered by the AMI Project. The increased level of customer choice, engagement, and satisfaction of customers that will result from these investments are difficult to assign a value to, but NIPSCO is confident that they are real and in alignment with what customers are demanding. Specific examples that will lead to an enhanced customer experience include:

- Remote connect and disconnect capabilities that will remove the need to schedule on-site visits;

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16 Witness Becker provides additional detail on IMPLAN and the calculated impact of the TDSIC investment, including AMI. Becker, pp. 18-20 and Confidential Attachment 1-B.

- The capability for the Company to perform on-demand reads to more accurately and quickly address customer questions; and
- The capability for the Company to "ping" a meter to provide information to a customer on whether a power issue is on the utility or customer side of the meter.

Additional benefits can come from the use of AMI as the foundational basis for follow-on programs, including customer-focused programs, programs to increase safety and reliability, and programs to enable a more efficient grid. These benefits would require additional investment to achieve but would all not be possible without AMI as the foundation.

While not quantified as part of the CBA, the contribution of these qualitative benefits is important and therefore relevant to the overall CBA results. In my opinion, the qualitative benefits further support the reasonableness of the AMI Project investments.

Q34. What type of follow-on programs could be enabled by AMI?

A34. AMI, in addition to the benefits presented above, is a foundational technology that provides data and functionality that can be used to offer follow-on programs in the years to come. At this time, NIPSCO has not analyzed the additional costs or resulting benefits of any follow-on programs and has not developed a plan addressing what follow-on programs might eventually be offered. While each of these programs may not be implemented in the near term, none of them will be possible to implement without the foundational investment in the AMI Project.[17] The list of potential programs is significant and includes:

- Enhanced Customer Programs
  - High Bill Alerts, Bill Date Selection, Prepaid Billing
  - Advanced Rate Options (Critical Peak Pricing, Peak Time Rebate, Time of Use)
  - DER Net Metering & EV Charging Rates
  - Enhanced Demand Response / Energy Efficiency Programs
- Improved Reliability/Safety
  - Hot Socket Detection
  - Interruption Trending
  - Vegetation Management
  - Improved Power Quality
  - Transformer Loading Analysis
- Efficient Distribution System Management
  - Advanced Load Profiling
  - Improved Connectivity Model

[17] Many of these potential programs will require advanced analytics, costs of which have also not been estimated or included in the AMI Project CBA or overall 2021-2026 Electric Plan.

- Open Neutral Analysis
- Incremental Conservation Voltage Reduction/Volt Var Optimization through AMI Voltage Sensing
- Optimized DERs/Renewables/Charging Infrastructure through Demand Insights for Load and Capacity Forecasting
- Smart Inverters

OBSOLESCENCE CONSIDERATION

Q35. Based on your industry experience, what concerns should utilities have regarding the potential for premature obsolescence of AMI-related technologies and investments?

A35. Public utilities should always carefully weigh and consider investments, especially large-scale capital expenditures, using a number of lenses, including consideration of possible obsolescence of technology. It is important to maintain flexibility and forward compatibility as key criteria for the selection of software, hardware, and other field devices associated with the continued modernization of the grid.

NIPSCO has demonstrated that these are priorities, via their plans to leverage an iterative planning and implementation process for field devices and other technologies that rely on the ongoing assessment of new and emerging capabilities that deliver the desired functionality and targeted customer benefits. NIPSCO will place considerable value on forward compatibility of the planned investments during vendor evaluation and the planning process and believes that the investments within the AMI Project will deliver long-lasting and sustainable benefits consistent with the CBA.

Q36. Specifically, what is West Monroe's perspective on the potential premature obsolescence of NIPSCO's proposed AMI technology?

A36. There are several reasons why this concern has been addressed, including specific technology features and capabilities of the AMI solution that will go into the selection criteria. The main feature of AMI technology that addresses this concern is the ability to leverage the communication network to update the meter and firmware (the software programmed into each meter) remotely, also known as "over the air" programing, allowing the Company to stay current on updates that deliver improvements and enhancements to the AMI system and the smart meters. This technology capability of "over the air" programing prolongs the useful life of the entire solution, from meters through the communication devices and network technology, positioning the Company to operate a long-term, flexible, and dependable AMI solution. Additionally, there is feedback and analysis on this specific topic by multiple third parties and industry researchers that has conclusively addressed this concern.

The status of AMI deployment across the United States provides evidence and support that this technology is not at risk of near-term obsolescence. This information and more can be referenced in a white paper authored by West Monroe, attached hereto as Attachment 3-C, which outlines West Monroe's perspective on this topic.

CONCLUSION

Q37. Please summarize your testimony.

A37. West Monroe worked closely with NIPSCO to identify the required inputs, assumptions, data points, and deployment timelines associated with the AMI Project that would enable accurate projection of the associated and comprehensive costs and benefits. This information was input into the established CBA methodology for analysis. The CBA demonstrates that the AMI Project investments are cost beneficial over a 15-year horizon. The planned investments deliver significant benefit to all customers across a wide range of areas, while also driving reductions in GHG emissions, an increase in new jobs, and economic growth in Indiana.

Q38. Does this conclude your prefiled direct testimony?

A38. Yes.

VERIFICATION

I, Christopher Kiergan, Senior Manager in the Energy and Utilities practice of West Monroe Partners, LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Christopher D Kiergan

Christopher D. Kiergan

Date: June 1, 2021

EDUCATIONAL AND EMPLOYMENT BACKGROUND AND QUALIFICATIONS OF CHRISTOPHER D KIERGAN

Christopher D Kiergan is a Senior Manager in West Monroe's Energy & Utilities (E&U) Practice and is part of the E&U's Chicago leadership team. He supports electricity and gas utility grid modernization strategy and planning; regulatory cost-benefit analyses for grid modernization initiatives and AMI; AMI deployment; AMI-OMS integration; post-AMI deployment initiatives, including smart LED streetlights, data analytics, and operational improvements; IT/OT network architecture analysis; ADMS and OMS strategy; and OT cyber security planning, including live isolation exercises on production systems to validate grid monitoring and control capabilities while disconnected from the corporate data network.

Prior to joining West Monroe in September 2013, Mr. Kiergan worked at various consulting firms, starting at Booz Allen & Hamilton in 1995 and including extended stints at CSC Index (1997-2001), Edgar, Dunn & Company (2002-2003), and DNV (formerly KEMA) (2003-2013). From 1995-1997, Mr. Kiergan focused on operational improvements to companies as diverse as an auto battery manufacturer/distributor, a nuclear material reprocessing plant, an aircraft manufacturer, and an auto seat manufacturer. Since joining CSC Index in 1997, Mr. Kiergan has focused primarily on electric and gas utilities, from major investor-owned utilities to small municipal utilities. During the period 1997-2008, he assisted utilities with improving operations across the utility value chain and developing processes for operating in deregulated markets. Since 2008, Mr. Kiergan has assisted utilities with all aspects of grid modernization, from strategy development to cost benefit analysis to deployment planning to deployment management. He has specific expertise in AMI, smart streetlights, IT/OT architecture, OMS and ADMS, cost benefit analysis, and project management. He has supported, authored, and sponsored testimony in several proceedings involving grid modernization and AMI cost benefit analysis, including testimony for Duke Energy Ohio and Duke Energy Indiana.

Mr. Kiergan earned his master's degree in Business Administration (MBA) from the Kellogg School of Management at Northwestern University (Evanston, IL) and a bachelor's degree in Mechanical Engineering (BSME) from the United States Naval Academy (Annapolis, MD). He also completed a Diploma in National Security and Strategic Studies from the Naval War College (Newport, RI). Between graduation from the U.S. Naval Academy and attending Kellogg, Mr. Kiergan spent 10 years as an officer and a helicopter pilot in the U.S. Navy. He achieved the rank of Lieutenant Commander, flew antisubmarine warfare and search-and-rescue missions from an aircraft carrier on multiple overseas deployments, and spent four years as an instructor pilot.

AMI PROJECT COST-BENEFIT ANALYSIS – DETAILED RESULTS

A. Cost-Benefit Analysis (CBA) Overview

As part of the planning process for the deployment of electric Advanced Metering Infrastructure (AMI) at NIPSCO, a 15-year CBA model was constructed by West Monroe Partners covering the years 2022-2036, with some pre-planning costs delineated in 2021. The fifteen-year time-period was selected to align with the estimated life of communications equipment. The capital and O&M costs identified are associated with the deployment of electric AMI in the NIPSCO service territory (2021-2026) as well as for the operation of this system through 2036. Costs were modeled in accordance with the phases outlined in an estimated schedule provided in this document project. Costs and benefits are sized in accordance with current service volumes performed and the number of customers served at NIPSCO. Costs and benefits were determined based on a combination of learnings from the previous AMR deployment, current costs at NIPSCO solicited through extensive stakeholder interviews, industry benchmarks, and West Monroe's AMI/Grid Modernization business case and cost-benefit analysis (CBA) experience with other utilities. As a result, there is a high degree of confidence that the sensitivity of the estimate, based on the current assumptions, is within the Class 3 ranges detailed by AACE (-10 to 20%, +10 to 30%). However, at present, no RFPs have been issued and no proposals from vendors have been received. Therefore, this estimate is considered a Class 4 estimate in alignment with NIPSCO's overall TDSIC program.

NIPSCO's guidance for financial modeling inputs are detailed below:

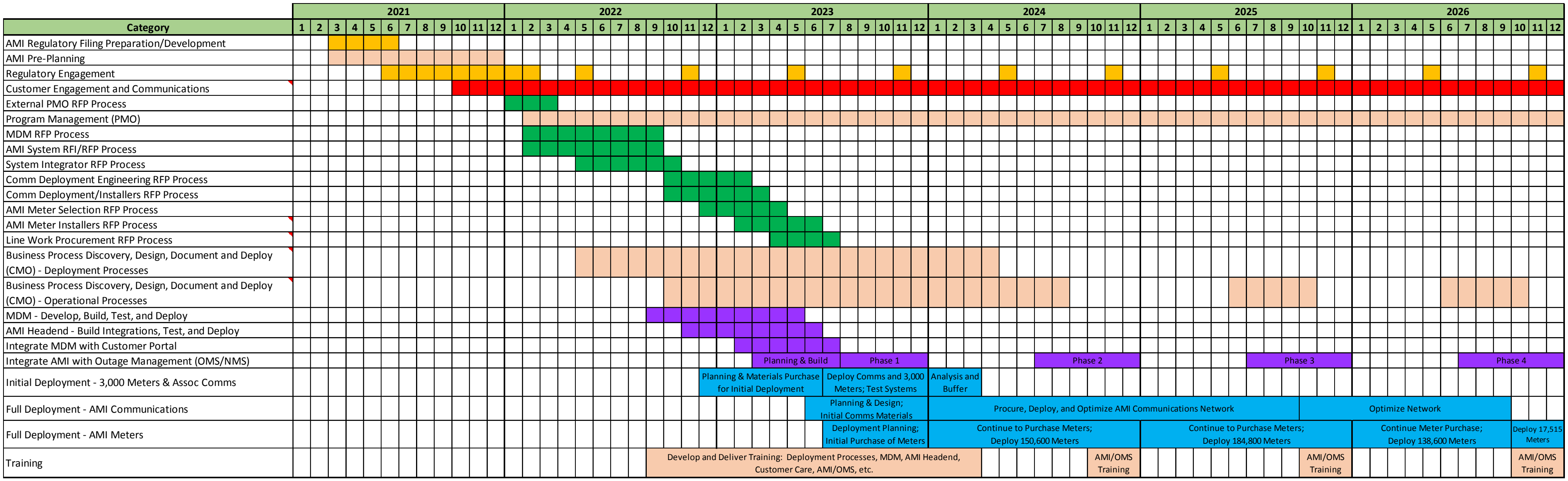
- WACC – Calculate present value dollars utilizing a 5.5% discount rate
- AFUDC – Apply 3.3% to capital costs with implementation times estimated to exceed three months, which includes primarily IT systems and IT integrations deployment and engineering design services for communication deployment points
- Corporate Overhead – Apply 15% to capital costs only
- Contingency – Apply 10% on all capital and O&M costs based on model sensitivity range falling within Class 3 estimate bounds and to align with overall TDSIC modeling
- Inflation – Apply inflation of 3.0% to internal labor rates only. External labor is assumed to be at a constant, contracted rate.

B. NIPSCO Electric AMI Project Timeline (Estimated/Projected)

The AMI Project's primary deployment is 2022-2026 with pre-planning activities scheduled in 2021. The major activities, delineated in the detailed draft timeline below, are comprised of:

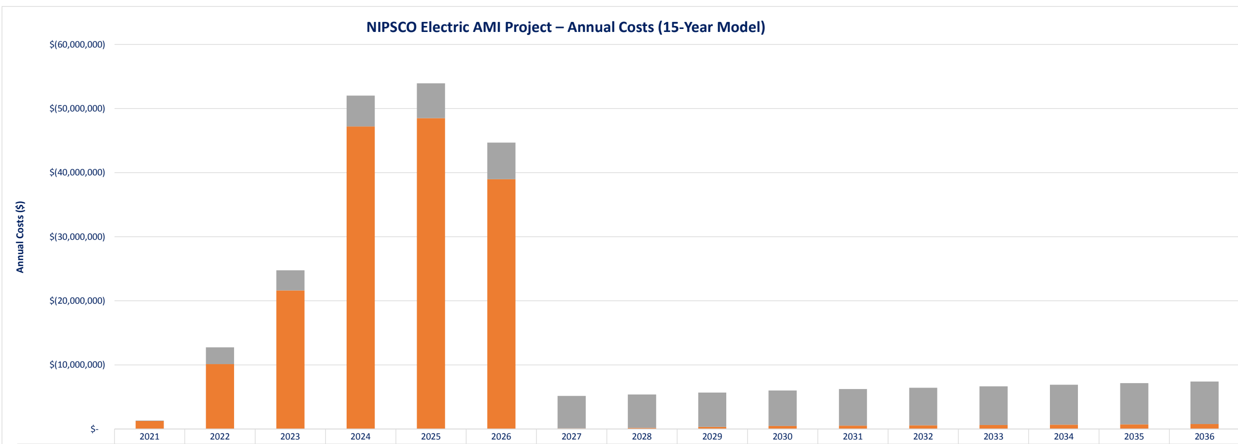
- 2021
  - Conduct AMI pre-planning activities
- 2022
  - Develop and/or issue RFPs for Meter Data Management System (MDMS), AMI system (communications and Headend system), AMI meters and deployment/installation/integration labor
  - Initiate MDMS Deployment
  - Develop deployment and operational processes
- 2023
  - Complete RFPs
  - Conduct/complete MDMS Deployment
  - Conduct/complete IT systems and integrations to existing NIPSCO applications
  - Develop and optimize deployment and operational processes
  - Deploy and analyze Initial Deployment (3,000 meters and associated communications) – Conducted to test deployment processes, operational processes, and end-to-end data flows
- 2024
  - Execute AMI full deployment – 150,600 meters and AMI communications
  - Optimize deployment and operational processes
  - Integrate AMI-OMS – Phase 2
- 2025
  - Execute AMI full deployment – 184,800 meters and AMI communications
  - Optimize deployment and operational processes
  - Integrate AMI-OMS – Phase 3
- 2026
  - Execute AMI full deployment – 156,115 meters
  - Optimize deployment and operational processes
  - Integrate AMI-OMS – Phase 4

AMI Project – Estimated Timeline



C. NIPSCO Electric AMI Project Costs

NIPSCO envisions electric AMI deployment beginning first with pre-planning activities in 2021, with continuing activities going through the deployment of the last electric AMI meter by the end of 2026. The costs in this deployment period are driven by the planned capital spend that is modeled to be $167.7 million, comprised of $145.5 million in direct costs (including contingency and materials tax, and $22.2 in indirect costs (corporate overhead and AFUDC). There is an additional, estimated $21.8 million in spend during the deployment phase attributable to O&M, $10.0 million in one-time O&M and $11.8 in recurring O&M. After deployment, the average annual O&M spend is estimated at $5.8 million whereas average annual capital is small, estimated at $0.5 million, and driven mainly by equipment replacements. The O&M costs incurred post-deployment are driven primarily by the newly deployed AMI Operations organization, monthly network service fees, and maintenance on new IT applications and associated integrations. An annual summary of the forecasted program costs is shown below:



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
NIPSCO O&M Costs	$(83,418)	$(2,640,860)	$(3,144,174)	$(4,817,025)	$(5,446,770)	$(5,697,079)	$(5,066,038)	$(5,212,757)	$(5,365,542)	$(5,524,630)	$(5,690,266)	$(5,862,704)	$(6,042,208)	$(6,229,051)	$(6,423,515)	$(6,625,896)
NIPSCO Capital Costs	$(1,232,899)	$(10,113,850)	$(21,617,510)	$(47,213,555)	$(48,503,884)	$(38,985,171)	$(84,158)	$(174,369)	$(317,703)	$(476,864)	$(525,952)	$(575,040)	$(624,128)	$(673,216)	$(722,305)	$(771,393)

1. NIPSCO Electric AMI Costs – Capital Costs[1]

The capital costs described in this section pertain to the deployment of AMI meters, communications network infrastructure, IT applications/software (MDMS, AMI Headend) and associated integrations (AMI Headend to OMS, MDMS to Billing, MDMS to Customer Portal), cyber security systems and testing, and associated program management and change management/business readiness teams needed to deploy the AMI system and transition NIPSCO successfully from deployment to on-going operations.

- AMI Meters and Installation Labor – The deployment of AMI meters is modeled to occur over a 4-year period from 2023 to 2026. Projected meter growth across customer classes is captured through the first year of full deployment. While the customer classes exist in the form of residential, commercial, and industrial classes, the meter costs and required installation labor included are based on five specific classes of meters: residential single-phase self-contained, commercial single-phase

[1] All component costs in this section exclude Contingency, Corporate Overhead, Materials Tax, and AFUDC. In the model these excluded components have their own line-item entry.

self-contained, commercial single-phase transformer-rated, commercial polyphase self-contained, and commercial polyphase transformer-rated.

With all meter types considered, there currently exist approximately 479,840 meters in the NIPSCO service territory. Projected meter growth across meter classes is captured in the model through the first year of full deployment. The meter growth rate is approximately 1.02% annually (average across meter classes), and this equates to 4,892 new meters installed each year. Therefore, a total of 494,515 AMI meters will be deployed by the end of 2026.

Modeled AMI Meter Deployment (Projected)

		2021	2022	2023	2024	2025	2026	
Line Item Name	**Growth Rates/ Initial Values**	**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Totals**
Residential Single Phase Meter Growth	0.90%	0	3,970	3,970	3,970	0	0	11,910
Comm Single Phase Self-Contained Meter Growth	2.73%	0	336	336	336	0	0	1,008
Comm Single Phase Trans-Rated Meter Growth	2.14%	0	48	48	48	0	0	143
Comm Polyphase Meter Growth	2.00%	0	274	274	274	0	0	823
Comm Polyphase Trans-Rated Meter Growth	2.52%	0	263	263	263	0	0	790
Total Meter Growth Modeled		0	4,892	4,892	4,892	0	0	14,675
Initial Deployment - Residential Single Phase Meters		0	0	2,850	0	0	0	2,850
Initial Deployment -Comm Single Phase Self-Contained Meters		0	0	48	0	0	0	48
Initial Deployment -Comm Single Phase Trans-Rated Meters		0	0	9	0	0	0	9
Initial Deployment - Comm Polyphase Meters		0	0	53	0	0	0	53
Initial Deployment - Comm Polyphase Trans-Rated Meters		0	0	40	0	0	0	40
Total Initial Deployment		0	0	3,000	0	0	0	3,000
AMI Full Deployment - Residential Single Phase Meters	441,127	0	0	0	137,887	168,089	144,211	450,187
AMI Full Deployment -Comm Single Phase Self-Contained Meters	12,313	0	0	0	4,066	4,956	4,252	13,274
AMI Full Deployment -Comm Single Phase Trans-Rated Meters	2,239	0	0	0	727	886	760	2,374
AMI Full Deployment - Comm Polyphase Meters	13,716	0	0	0	4,437	5,409	4,640	14,486
AMI Full Deployment - Comm Polyphase Trans-Rated Meters	10,445	0	0	0	3,429	4,180	3,586	11,194
Total AMI Full Deployment	479,840	0	0	0	150,545	183,520	157,450	491,515
Total AMI Meters Deployed		0	0	3,000	150,545	183,520	157,450	494,515
Cumulative AMI Meters Deployed and In Service		0	0	3,000	153,545	337,065	494,515	
Existing AMR Meters		479,840	484,732	486,623	340,970	157,450	0	

At this time, the currently modeled plan is to replace the vast majority of meters with AMI meters. Meters not currently modeled for replacement during the 2024-2026 full deployment include approximately 350 large industrial, MV-90-read meters that require specific real-time data transmission and advanced data measuring functionality.

After deployment, all meter replacements are AMI meters with a percentage occurring each year. In the first three years after a meter is installed, warranty costs cover the cost of the meter but not the installation labor. Currently, AMR meters are replaced at a rate of approximately 2.5% per year across customer classes. Failure rates are modeled to double every 15 years. The AMI failure rate begins at one-third the current AMR failure rate. Over the course of the 15-year model, it is estimated that $3.1 million will be spent in materials costs for AMI meter replacements.

While most AMI meters are modeled to be deployed by contract labor, all transformer-rated meters are modeled to be deployed by NIPSCO crews. Between the pilot and deployment, meter costs are estimated at $19.5 million in labor and

$55.6 million in physical meter costs. It is modeled that warehouse storage will be needed to maintain the supply of meters during deployment. Estimating that four locations at $5,000 per month or one larger facility, the estimate for warehouses during deployment comes to $960,000.

Additionally, it is modeled that 2.5% of contractor-installed residential meters will need to be returned to the utility due to access or other concerns. In this case, these meters are modeled to be deployed with NIPSCO's internal exchange rate. Furthermore, additional costs are captured for contractor-installed meters which require socket, a-base, and weather head repairs, as well as line wiring extensions. This is modeled to occur for 1.5% of meter installations. Costs associated with these issues are included in the deployment labor costs highlighted above.

As an added cost to increase the safety of crews performing installations in high population portions of the territory, it is estimated that six months of the deployment will occur in regions where security guards will be utilized. These costs are also included in the deployment labor costs.

- AMI Communications Network Equipment and Installation Labor – The communications network serves as the backbone for the AMI network that smart meters will leverage for communication. AMI communications consist of:

  - Communications card within AMI meters (modeled as part of the meter cost)
  - Communications node that collects data from meters and transmits that data back to the utility – access points and relays in a mesh design and base stations and relays in a point-to-multipoint design
  - Field-area network (FAN) for communications between the meters and the communications node
  - Backhaul network to move data from the communications node to the AMI Headend system

  The costs included represent the physical infrastructure such as communications node and relays, deployment of this infrastructure, engineering design of installation points, and the AMI System vendor costs associated with the execution of the network design, testing, and optimization. Two primary network designs have been modeled as options for NIPSCO, a mesh and point-to-multipoint approach. The mesh design is the current base case in the model outputs presented, but the two are nearly equivalent from a total cost perspective given the nature of the service territory and the available infrastructure currently in place. NIPSCO plans to assess both network designs in the vendor RFP/selection phase of this program to achieve the most optimal solution. With the mesh design, there are conservatively estimated to be 1,500 meters per access point and 2.5 relays per access point. With the point-to-multipoint design, in order to create an overlapping communications design, the number of base stations/AMI collectors is estimated at one per 26 square miles of service territory. In the mesh design, the all-in deployment costs, including materials, installation labor, network design, network set-up, network optimization, and installation point engineering design is estimated to be $12.4 million. A minimal failure rate of communications assets is modeled, resulting in an estimate of $630,400 spent in materials costs for AMI communications asset replacements over the course of the 15-year model.

- IT Systems – Meter Data Management System (MDMS), Other Systems and Integrations – Having the correct systems with integrations throughout the corporate enterprise is crucial to realizing benefits from AMI. The two primary systems/applications that are required for AMI are:

  - MDMS – Modeled as an onsite, NIPSCO-owned application, the MDMS is the central repository where data is correlated and supplied to MDMS, CIS, and the Customer Portal
  - AMI Headend – Modeled as a licensed application that sits in the application vendor's data center, the AMI Headend is the software that enables the utility to monitor and control meters and communications nodes. NIPSCO would pay a license fee per endpoint for the AMI Headend provided through a software-as-a-service (SaaS) model.

  In addition to hardware and software costs, the labor costs associated with development and deployment of these systems and related integrations are captured in the model. For optimal efficiency and flexibility, AMI-related integrations will be designed to utilize middleware to avoid point-to-point integrations. The integrations modeled are shown below along with uses for the data communication pathways.

  - Deployment Tool to AMI Headend – Initial AMI meter information to AMI Headend
  - AMI Headend to MDMS – Meter read data
  - MDMS to CIS – Billing determinants
  - MDMS to Customer Portal – Usage data for customer review
  - MDMS and AMI Head-end to Outage Management System (OMS) – Alarms and events from meters to OMS
  - OMS to AMI Head-end – Pinging meters for outage identification and restoration verification

  The capital costs associated with deploying these components, in terms of labor, software, and hardware, are estimated to be $16.5 million.

- Cyber Security – With the addition of hundreds of thousands of communicating devices added to the NIPSCO territory, AMI cyber security solutions that complement those provided by the network provider will mitigate risks to NIPSCO. These costs require NIPSCO internal labor during deployment and hardware/software costs for systems capable of performing firewall management, access and authorization/authentication, active directory validation, vulnerability scanning, and file integrity monitoring. Furthermore, planned penetration testing accounts for a portion of the costs. Cyber security costs associated with the AMI Project are estimated to be $2.0 million.

- Program Management Office (PMO) – The program management team will be comprised of a number of both internal and external resources and subject matter specialists dedicated to a wide range of tasks including project management (schedule, scope, budget tracking), issue tracking and resolution, business requirement and RFP development, deployment management (MDMS, communications network, meters), integration management, business process design for deployment processes, and more. PMO capital costs are estimated to be $14.4 million.

- Change Management Office (CMO)/Business Readiness – This change management group is responsible for the strategy and execution of internal business process design, specifically for deployment process. Furthermore, change management defines and organizes processes required to bring NIPSCO through the AMI transformation, including organizational design and stand-up, resource transition planning, and training. Key challenges will be the functionality 'releases' of AMI/MDM software, integrations, and on-going support and governance protocols defined for cyber security and the newly stood up organizations. CMO capital costs are estimated to be $4.7 million.

2. NIPSCO Electric AMI Costs – O&M Costs

The O&M costs described in this section of the report pertain to both one-time costs associated with the deployment and ongoing or recurring costs associated with operational processes. One-time O&M costs are comprised of customer engagement, project management and change management as it applies to ongoing operational process design and development. On a recurring basis, O&M costs will include the AMI IT and AMI Operations organization costs, AMI network service fees, system maintenance that NIPSCO incurs, and the labor costs associated with standard AMI meter replacements.

- Customer Outreach and Education – Several resources will be responsible for the creation and execution of the overall customer outreach and education effort associated with the AMI deployment. This will include tactics, staged communications, messaging development, stakeholder communication, evaluation and measurement of results, and ongoing internal and external reporting. Bill inserts, mailed fact sheets, door hangers, web videos, social media campaigns, and town halls are all options to consider. Benefit realization will be positively impacted by upfront successes realized through high customer engagement. Customer outreach and education costs during 2021-2026 are estimated to be $2.9 million.

- Project Management and Change Management/Business Readiness – These costs are the non-capital components of the above-described Project Management/Business Readiness components and pertain to the regulatory engagement, customer engagement, design and development of ongoing operational processes, internal training, etc. that will occur throughout the electric AMI Project. Benefit realization will be positively impacted by upfront successes and process execution across the NIPSCO organization. PMO/CMO O&M costs are estimated to be $6.2 million during deployment.

- AMI IT – AMI IT is a new function, modeled as contractors to align with current NIPSCO application support operations, for the management and execution of core AMI system implementation, integration, go-live, and ongoing maintenance/support/ upgrades. Supported systems include the MDMS, AMI Headend, and related integrations such as connections to OMS, Billing, and Customer Portal. It is estimated that about three FTEs of contract support will be required annually during 2022-2025, followed by steady-state support of about one-and-a-half FTEs annually starting in 2026. AMI IT O&M costs are estimated to be $2.4 million during deployment and average $616,000 annually post-deployment. (Note: It is estimated that an additional $1.6 million in AMI IT costs will be assigned to capital during deployment to address specific deployment activities; this $1.6 million is included in the IT Systems costs delineated in the capital section above.)

- AMI Operations – A new organization to be established at NIPSCO, AMI operations will be responsible for the operation of the growing AMI footprint of communications devices and meters. Responsibilities will include the monitoring of performance (read rate, alarms, other KPIs), leveraging data analytics tools to analyze network and meter data, coordinating with field resources to resolve communications issues, upgrading firmware, certifying meters, and many other tasks. Standup of the AMI Operations organization will tentatively occur in early 2022. The model currently forecasts 1.75 FTEs in 2022 and a ramp up from 3.25 FTEs in 2023 to a steady-state level of 7.25 FTEs in 2025. Steady-state staffing will be greater than the initial staffing due to two primary factors: 1) the increased amount of data to be processed and reviewed due to the full deployment of AMI meters and AMI communications devices and 2) new analyses that will utilize data from meters to improve operations and asset management. AMI Operations O&M costs are estimated to be $2.3 million during deployment and average $1.5 million annually post-deployment. (Note: It is estimated that an additional $2.0 million in AMI Operations costs will be assigned to capital during deployment to address specific deployment activities, including design and execution of deployment processes.)

- AMI Headend SaaS, Maintenance, and Network Support Fees – The AMI Headend will reside in the vendor's data center and will provide data to NIPSCO via a SaaS delivery model. O&M costs will be driven by the following fees: annual SaaS fees, product support fees, and maintenance fees, all based on the number of endpoints/meters deployed. These fees will begin being incurred as meters are deployed and will reach steady state upon full deployment. This set of fees is estimated to be $19.7 million total during the 2022-2036 timeframe, averaging $1.6 million annually after full deployment.

- Data Transfer Fees – As previously stated, the current base model assumes a mesh communications network. Communications from the meters to the communications node is typically via 900 MHz radios for which there is no fee. Backhaul communications from the communications node to the AMI Headend is modeled as a mix of existing/planned NIPSCO backhaul communications (fiber or microwave) and public carrier cellular. Public carrier cellular communications will have a data transfer fee based on the number of endpoints and/or amount of data. Data transfer fees are estimated to be $2.7 million total during the 2022-2036 timeframe, averaging $218,000 annually after full deployment.

- IT Systems Maintenance, including MDMS, Integrations, and Cyber Security – Hardware and Software Maintenance – In addition to AMI IT costs, the model estimates the O&M costs required for the software and hardware that is installed as part of the AMI Project. Using benchmarks of 15% of software costs and 10% of hardware costs, O&M costs for IT systems are estimated to average $684,500 annually after full deployment.

- AMI Meter and Communications Asset Replacement Labor – In the model, AMR replacements are not reduced by any degree until AMI deployment begins. After deployment of AMI meters, a percentage of installed AMI meters will be replaced every year. The labor rate of these installations is greater than the rate of a mass deployment of meters because they are carried out by NIPSCO internal resources rather than by contractors in bulk. Additionally, there will be labor costs associated with replacing any of the AMI communications network that requires replacing during the modeled timeframe (2021-2036). Estimated replacement labor costs for AMI meters and AMI communications assets total $7.4 million over the 15-year model.

Tables delineating annual capital costs and O&M expenses during deployment and average annual costs post deployment are shown on the next two pages.

Estimated NIPSCO AMI Project Capital Costs (2021-2036)

Capital	2021 Capital	2022 Capital	2023 Capital	2024 Capital	2025 Capital	2026 Capital	Deployment Totals	2027-2036 Averages	2027-2036 Totals	Total
AMI Perpetual License Fee	$0	$0	$143	$310,966	$734,080	$629,800	$1,674,988	$0	$0	$1,674,988
AMI to OMS Integration	$0	$0	$306,090	$768,545	$675,102	$315,927	$2,065,665	$0	$0	$2,065,665
AMI IT Organization	$0	$347,625	$716,108	$245,864	$253,239	$0	$1,562,836	$0	$0	$1,562,836
AMI Operations Organization	$0	$167,641	$470,548	$452,933	$600,238	$309,123	$2,000,483	$0	$0	$2,000,483
Commercial AMI Meters	$0	$0	$30,834	$2,598,744	$3,167,962	$2,717,936	$8,515,477	$75,577	$755,773	$9,271,249
Residential AMI Meters	$0	$0	$296,400	$14,340,249	$17,481,275	$14,997,969	$47,115,893	$231,804	$2,318,043	$49,433,936
Commercial Meter Deployment	$0	$0	$23,992	$2,107,383	$2,627,865	$2,306,603	$7,065,844	$0	$0	$7,065,844
Residential Meter Deployment	$0	$0	$56,003	$3,926,814	$4,509,810	$3,893,595	$12,386,222	$0	$0	$12,386,222
AMI Comms Equipment (Access Points and Relays)	$0	$0	$444,677	$3,102,803	$0	$63,040	$3,610,520	$63,040	$630,400	$4,240,920
AMI Comms Equipment Installation (Access Points and Relays)	$0	$0	$9,621	$407,888	$390,991	$0	$808,500	$0	$0	$808,500
Program Management	$760,342	$1,734,959	$2,511,286	$3,643,725	$3,366,806	$2,420,382	$14,437,500	$0	$0	$14,437,500
Change Management / Business Readiness	$199,511	$906,472	$1,780,126	$1,109,517	$452,732	$230,002	$4,678,360	$0	$0	$4,678,360
Deployment Warehouses	$0	$0	$240,000	$240,000	$240,000	$240,000	$960,000	$0	$0	$960,000
Engineering for Communications Deployment on Poles	$0	$0	$13,745	$582,698	$558,558	$0	$1,155,000	$0	$0	$1,155,000
MDM to Customer Portal Integration	$0	$0	$1,268,270	$0	$0	$0	$1,268,270	$0	$0	$1,268,270
MDM, including integration to AMI and CIS	$0	$4,331,230	$5,635,582	$0	$0	$0	$9,966,812	$0	$0	$9,966,812
Network Deployment Costs (Software and Network)	$0	$0	$1,401,512	$1,893,883	$1,892,106	$1,542,500	$6,730,000	$0	$0	$6,730,000
Network Deployment Tools	$0	$0	$117,000	$0	$0	$0	$117,000	$0	$0	$117,000
Cyber Security	$0	$288,694	$1,394,709	$306,275	$0	$0	$1,989,677	$0	$0	$1,989,677
Subtotal	**$959,853**	**$7,776,621**	**$16,716,644**	**$36,038,287**	**$36,950,764**	**$29,666,877**	**$128,109,045**	**$370,422**	**$3,704,216**	**$131,813,261**
Contingency	$95,985	$771,578	$1,645,678	$3,741,014	$3,846,169	$3,084,984	$13,185,408	$37,042	$370,422	$13,555,830
Subtotal + Contingency	**$1,055,838**	**$8,548,198**	**$18,362,323**	**$39,779,301**	**$40,796,933**	**$32,751,860**	**$141,294,453**	**$407,464**	**$4,074,637**	**$145,369,091**
Corporate Overhead	$158,376	$1,282,230	$2,754,348	$5,966,895	$6,119,540	$4,912,779	$21,194,168	$61,120	$611,196	$21,805,364
Subtotal + Contingency + Overhead	**$1,214,214**	**$9,830,428**	**$21,116,671**	**$45,746,196**	**$46,916,473**	**$37,664,639**	**$162,488,621**	**$468,583**	**$4,685,833**	**$167,174,454**
Tax	$0	$52,500	$87,558	$1,314,865	$1,462,247	$1,261,326	$4,178,495	$25,930	$259,295	$4,437,790
AFUDC (Direct)	$17,128	$211,833	$379,445	$140,430	$115,406	$54,772	$919,014	$0	$0	$919,014
AFUDC (Indirect)	$1,557	$19,090	$33,836	$12,064	$9,758	$4,433	$80,738	$0	$0	$80,738
Capital Total: All Costs	**$1,232,899**	**$10,113,850**	**$21,617,510**	**$47,213,555**	**$48,503,884**	**$38,985,171**	**$167,666,868**	**$494,513**	**$4,945,128**	**$172,611,997**
Capital Direct Total: Subtotal + Contingency + Tax	**$1,055,838**	**$8,600,698**	**$18,449,880**	**$41,094,165**	**$42,259,180**	**$34,013,186**	**$145,472,948**	**$433,393**	**$4,333,933**	**$149,806,881**

Estimated NIPSCO AMI Project O&M Expenses (2021-2036)

O&M Costs	2021 O&M	2022 O&M	2023 O&M	2024 O&M	2025 O&M	2026 O&M	Deployment Totals	2027-2036 Averages	2027-2036 Totals	Total
AMI IT Organization	$0	$115,875	$238,703	$737,591	$759,718	$521,673	$2,373,560	$615,981	$6,159,812	$8,533,372
AMI Operations Organization	$0	$167,641	$156,849	$452,933	$600,238	$927,368	$2,305,029	$1,460,023	$14,600,227	$16,905,256
AMI Saas, Mnt, Network Support Fees	$0	$0	$6,418	$458,250	$1,287,319	$1,627,275	$3,379,262	$1,627,275	$16,272,747	$19,652,008
AMI to OMS Software Maintenance	$0	$0	$0	$65,564	$67,531	$69,556	$202,651	$82,131	$821,308	$1,023,959
Commercial Meter Deployment	$0	$0	$0	$0	$0	$0	$0	$229,616	$2,296,164	$2,296,164
Residential Meter Deployment	$0	$0	$0	$0	$0	$0	$0	$425,525	$4,255,249	$4,255,249
AMI Comms Equipment Installation (Access Points and Relays)	$0	$0	$0	$0	$0	$84,000	$84,000	$84,000	$840,000	$924,000
Program Management	$0	$1,445,963	$256,477	$220,088	$174,492	$133,990	$2,231,010	$0	$0	$2,231,010
Change Management / Business Readiness	$0	$125,829	$1,249,366	$1,312,438	$782,008	$517,618	$3,987,259	$0	$0	$3,987,259
Customer Outreach and Education	$75,834	$548,120	$557,493	$567,147	$577,091	$587,333	$2,913,019	$0	$0	$2,913,019
Data Transfer Fees	$0	$0	$2,596	$112,658	$218,160	$218,160	$551,574	$218,160	$2,181,600	$2,733,174
MDM Maintenance	$0	$0	$397,838	$409,773	$422,066	$434,728	$1,664,404	$513,318	$5,133,177	$6,797,580
MDM to Customer Portal Software Maintenance	$0	$0	$0	$32,782	$33,765	$34,778	$101,325	$41,065	$410,654	$511,979
VPN Tunnels for Communications from Back-Office to AMI Headend	$0	$0	$571	$24,787	$48,000	$48,000	$121,358	$48,000	$480,000	$601,358
Warranties (Comunications Equipment)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal - Direct Costs	**$75,834**	**$2,403,428**	**$2,866,311**	**$4,394,009**	**$4,970,389**	**$5,204,479**	**$19,914,450**	**$5,345,094**	**$53,450,938**	**$73,365,388**
Contingency	$7,583	$237,432	$277,863	$423,016	$476,381	$492,600	$1,914,876	$459,167	$4,591,670	$6,506,546
O&M Total: Direct + Contingency	**$83,418**	**$2,640,860**	**$3,144,174**	**$4,817,025**	**$5,446,770**	**$5,697,079**	**$21,829,326**	**$5,804,261**	**$58,042,608**	**$79,871,934**

O&M	2021 O&M	2022 O&M	2023 O&M	2024 O&M	2025 O&M	2026 O&M	Deployment Totals	2027-2036 Averages	2027-2036 Totals	Total
Recurring (Subtotal)	$0	$283,516	$802,975	$2,294,336	$3,436,797	$3,965,538	$10,783,163	$5,345,094	$53,450,938	$64,234,100
One-time/Non-recurring/ (Subtotal)	$75,834	$2,119,912	$2,063,336	$2,099,673	$1,533,591	$1,238,941	$9,131,287	$0	$0	$9,131,287
Recurring (Contingency)	$0	$28,008	$77,841	$220,878	$329,396	$375,335	$1,031,459	$459,167	$4,591,670	$5,623,129
One-time/Non-recurring (Contingency)	$7,583	$209,423	$200,022	$202,138	$146,985	$117,265	$883,417	$0	$0	$883,417
Recurring (Total)	$0	$311,524	$880,816	$2,515,215	$3,766,193	$4,340,873	$11,814,622	$5,804,261	$58,042,608	$69,857,230
One-time/Non-recurring (Total)	$83,418	$2,329,335	$2,263,358	$2,301,811	$1,680,577	$1,356,206	$10,014,704	$0	$0	$10,014,704
Total	**$83,418**	**$2,640,860**	**$3,144,174**	**$4,817,025**	**$5,446,770**	**$5,697,079**	**$21,829,326**	**$5,804,261**	**$58,042,608**	**$79,871,934**

D. Electric AMI Program Benefits

The benefits described in this section of the report were quantified based on estimates, benchmark data, and current internal costs solicited through interviews held with the NIPSCO groups impacted by the proposed advanced metering infrastructure program. The benefits fall into several subcategories:

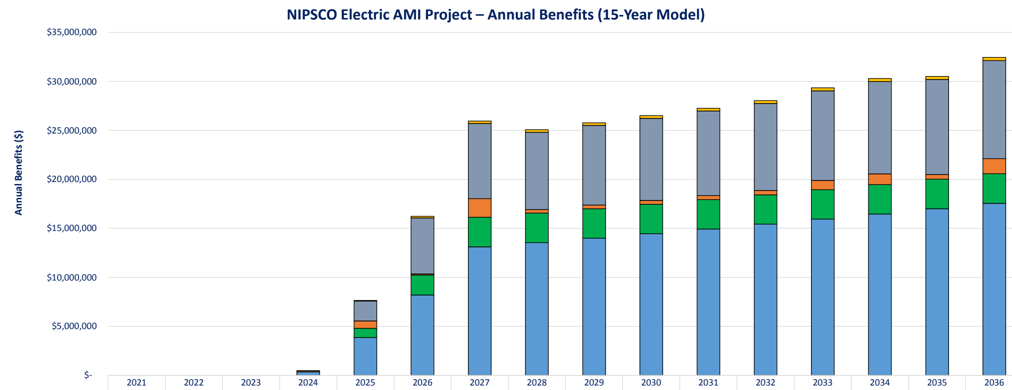
- NIPSCO Operational Benefits
  - NIPSCO Avoided Capital
  - NIPSCO Additional Cost of Service Reduction
  - NIPSCO O&M and Expense Reduction
- Customer Benefits
  - Improved Reliability
  - Energy Savings
  - Societal Benefits
  - GHG Emissions
  - Economic Impact

NIPSCO operational benefits are primarily driven by the NIPSCO O&M and Expense Reduction benefit category. These benefits pertain to meter reading, meter servicing, outage management, AMR software and licensing cost avoidance, residential and commercial AMR meter replacements avoided, bad debt, and billing exceptions. These equate to about $164.9 million in expected savings. Together, NIPSCO Avoided Capital and Additional Cost of Service Reductions benefit categories yield NIPSCO an additional $41.9 million in expected operational benefits enabling NIPSCO to realize a total of $206.8 million in benefits without considering the benefit of other programs enabled by AMI. All internal labor related benefits are calculated utilizing loaded salaries.

For the Customer Benefit equaling $98.7 million, this figure is driven primarily by a reduction in service interruption minutes during outage events throughout the year that can likely be mitigated through insights from AMI data. Other customer benefits are estimated through electricity savings that can emerge through customer engagement with usage data insights made available on the customer portal.

The societal benefits of the AMI Project are projected to be large, equaling $1,308.6 million in total. Depending on the stakeholders considering this program, not all societal benefits are of equal weight, but these numbers are reflective of societal benefits to NIPSCO customers and to economic benefits across the United States.

Additional details for NIPSCO Operational and Customer benefits are provided below:



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Electricity Savings (Residential)	$-	$-	$-	$1,207	$63,116	$166,829	$253,284	$256,738	$267,023	$275,152	$284,877	$294,031	$301,476	$306,286	$317,463	$327,464
Customer Reliability Improvement (Residential, Commercial, Industrial)	$-	$-	$-	$-	$2,035,546	$5,705,837	$7,664,265	$7,894,193	$8,131,019	$8,374,949	$8,626,198	$8,884,983	$9,151,533	$9,426,079	$9,708,861	$10,000,12
NIPSCO Avoided Capital	$-	$-	$-	$87,727	$746,915	$103,329	$1,912,137	$354,819	$370,947	$387,076	$403,204	$419,332	$952,960	$1,084,088	$467,716	$1,539,790
NIPSCO Additional Cost of Service Reductions	$-	$-	$-	$18,260	$934,569	$2,051,581	$3,009,917	$3,009,917	$3,009,917	$3,009,917	$3,009,917	$3,009,917	$3,009,917	$3,009,917	$3,009,917	$3,009,917
NIPSCO O&M and Expense Reductions	$-	$-	$-	$357,633	$3,866,383	$8,202,607	$13,120,21	$13,550,90	$13,996,39	$14,457,13	$14,933,62	$15,426,39	$15,936,00	$16,463,01	$17,008,00	$17,571,59

1. NIPSCO Electric AMI Benefit – Avoided Capital

Benefits classified as avoided capital expenditures include the vehicle purchases avoided by retirements in the meter reading fleet, avoided AMR collector hardware refresh costs, and avoided AMR meter replacements. These benefits are small, $8.8 million over the 15-year modeled period, and do not drive the overall AMI project benefits.

Avoided Capital Benefits	Deployment Total	2027-2036 Average	2027-2036 Total	2021-2036 Total
Vehicle Purchases	$632,500	$274,439	$2,744,392	$3,376,892
AMR Collector Hardware	$0	$103,500	$1,035,000	$1,035,000
Residential AMR Meter	$200,021	$268,930	$2,689,302	$2,889,323
Commercial AMR Meter	$105,449	$142,338	$1,423,376	$1,528,825
Avoided Capital Total	**$937,971**	**$789,207**	**$7,892,070**	**$8,830,040**

- Meter Reading Vehicle Purchases – Based on the current number of vehicles being utilized to service electric AMR customers, these numbers multiplied by the average truck cost are modeled as an added capital benefit based on trucks having an 8-year lifespan on average.

- AMR Collector Hardware - Currently, there are annual costs associated with the AMR system software and licenses as well as refresh costs on the physical mobile collector equipment occurring every 3-5 years. Due to accounting splits, 36% of these costs are allocated to the electric AMI CBA. We are modeling that the AMR system is discontinued after AMI deployment from an electric perspective. Beyond refresh/maintenance costs associated with AMR software and AMR hardware, the discontinuation of the system would alleviate the need for integrations to be built between the FCS (AMR) and the MDMS and/or Customer Portal. Handheld equipment is comprised of vendor mobile radios, computers in trucks, desk cradles, and optical probes.

- Replaced AMR Meters - In the model, AMR replacements are not reduced by any degree until AMI deployment begins. A portion of AMR replacements are reduced beginning during the AMI deployment years proportional to the percentage of the territory being deployed each year. After deployment, all meter replacements are AMI meters. The failure rate of AMR meters is higher than AMI meters initially due to the older AMR asset life.

2. NIPSCO Electric AMI Benefit – Additional Cost of Service Reduction

Benefits categorized as a reduction in the additional cost of services provided by NIPSCO reflect costs that the utility incurs due to unbillable electric utilization that ultimately gets accounted for and socialized back into NIPSCO customer rates. Insights from AMI can reduce a couple of these higher cost of service drivers such as (1) electricity generation that is unbillable from theft and (2) unbillable usage from consumption on inactive meters. These benefits are larger than Avoided Costs benefits at $33.1 million over the 15-year modeled period, but also do not drive the overall AMI project benefits.

Additional Cost of Service Reduction Benefits	Deployment Total	2027-2036 Average	2027-2036 Total	2021-2036 Total
Theft	$881,740	$883,357	$8,833,566	$9,715,307
Consumption on Inactive Meters	$2,122,669	$2,126,560	$21,265,603	$23,388,273
Additional Cost of Service Reduction Total	**$3,004,410**	**$3,009,917**	**$30,099,170**	**$33,103,580**

- Theft values are impacted through advanced monitoring and analytics solutions which trigger alerts and alarms. Additionally, AMI meters can detect tampering. Theft is currently modeled based on a percentage of total residential revenue sales with AMI modeled to impact 50% of this theft figure based on industry benchmark data. Residential revenue is approximately equal to $511 million based on a bill of $0.147258/kWh. Benchmarks indicate that a good approximate for electricity theft is equal to 0.333% of residential revenue. This would yield $1.7 million in potential with 50% reduced in the model, approximately $9.7 million in total benefit over the 15-year model.

- Consumption on Inactive Meters – This occurs with meters that are not turned off but are, yet, not associated with an account. This typically occurs as a result of the move-in and move-out of customers. NIPSCO has a high volume of move-in and move-outs every year. The cost of electricity per kWh is applied to the total kWh saved through reducing consumption on inactive meters. Benchmarks indicate that a good approximate for consumption on inactive meters is equal to 0.15% of total energy production. This would equate to about $23.4 million in benefit over the 15-year model.

3. NIPSCO Electric AMI Benefit – O&M and Expense Reduction

NIPSCO O&M and expense reduction benefits pertain to meter reading, meter servicing, outage management, AMR software and licensing avoidance, residential and commercial AMR meter replacements avoided, bad debt, and billing exceptions. Using AMI data and insights, opportunities will be available to enhance and even automate activities, processes, and analysis performed by the above service areas at NIPSCO. I t will be a transformational effort at NIPSCO to achieve these results across functional areas with shifting responsibilities and capabilities, and this goes to show the importance of a well-structured change management / business readiness effort that will be needed throughout the deployment phase of this program.

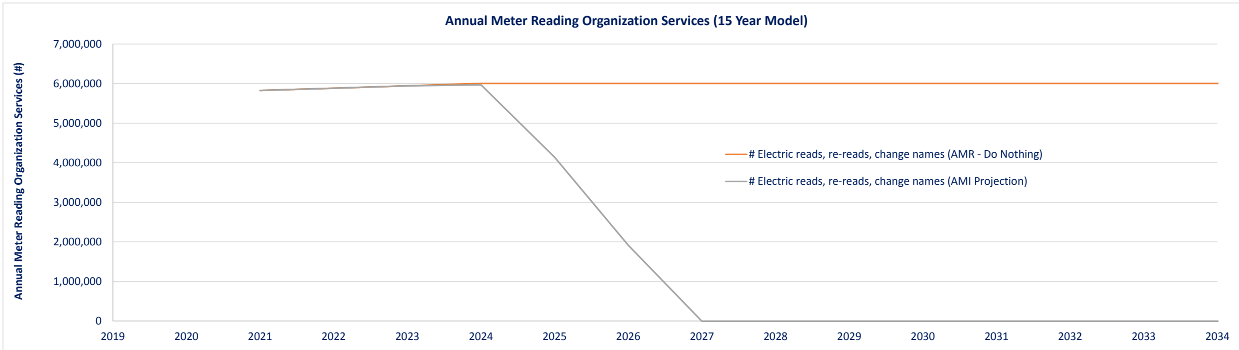
Given the number of services described above, these benefits represent the largest category of operational benefits to NIPSCO, and despite the annual O&M costs described in the cost sections above, current modeling estimates indicate that a net reduction in NIPSCO O&M would occur after AMI is deployed and integrated into NIPSCO operations. In total, there is expected to be greater than $164.9 million in O&M savings within the 15-year model and about $15.2 million in annual savings realized on an on-going basis post deployment. When calculating a net O&M, balancing O&M savings with O&M costs in the model, the model estimates just over $85.0 million in net O&M savings over the 15-year period and about $9.4 million in annual net savings realized on an on-going basis post deployment. Additional O&M benefits may be available due to unquantified activities that other NIPSCO service groups perform that work in tandem on certain electric meter service order responses such as power cuts. Additional insights may become available through analytics insights and other programs that get initiated over time.

O&M and Expense Reduction Benefits	Deployment Total	2027-2036 Average	2027-2036 Total	2021-2036 Total
Meter Reading	$1,671,760	$1,996,320	$19,963,204	$21,634,964
Meter Servicing	$7,327,515	$8,752,566	$87,525,660	$94,853,174
Outage Management	$1,650,341	$1,970,804	$19,708,044	$21,358,385
AMR Software and Licensing	$0	$62,646	$626,458	$626,458
Billing	$0	$0	$0	$0
Residential AMR Meter Replacement	$686,530	$1,131,361	$11,313,606	$12,000,136
Commercial AMR Meter Replacement	$368,034	$608,866	$6,088,655	$6,456,689
Bad Debt	$722,443	$723,767	$7,237,670	$7,960,113
O&M and Expense Reduction Total	**$12,426,623**	**$15,246,330**	**$152,463,295**	**$164,889,918**

Detail on each of the listed O&M expense reduction categories are below:

- Meter Reading - At present, the meter reading group within NIPSCO perform standard reads, re-reads, and change name service orders after move-in and move-out occurrences. It is modeled that these truck rolls will be avoidable and fully captured in the years following AMI deployment. Any non-AMI meter reading requirements (current opt-outs, AMI opt-outs, possibly tie meters) will be performed by Meter Servicing. Though NIPSCO, by regulation, cannot replace an AMR meter with an older manual read meter, these meters could still be read manually if someone opts out of AMI, just as AMR opt-outs are read today. Additionally, customer growth is modeled up through deployment, and inflation is modeled at 3.0% annually in these benefit calculations.

  At present, there are approximately 5,750,000 meter reads that occur each year. Additionally, there are approximately 1,250 re-reads that occur as well as 67,000 change name service orders after move-in and move-out occurrences. It is modeled that these truck rolls will be avoidable and fully captured after each year of AMI deployment. The reduction in these reads translates into $21.6 million in benefits in terms of savings in labor costs and meter reading vehicle expenses.



- Meter Servicing - Presently, the electric meter services, gas services and line department organizations performs approximately 23,500 orders annually for regular electric turn-on/shut-off activities and an additional 18,700 electric service orders for non-pay. Beyond this, the organization also performs approximately 5,200 hours of electric meter reading activities annually to gather data for time of use rates and for rate study purposes.

  Most of the truck rolls associated with these activities can be avoided as the services are performed remotely through AMI, but existing door knock policies have an impact on the benefits that can be realized. Currently, door knocks for non-pay are modeled to be retained, but it is assumed that less expensive hourly labor could be utilized to simply notify the customer. The overall benefit modeled for the reduction in these meter servicing activities is $94.9 million over the 15-year period. If, in the future, NIPSCO decided to pursue a regulatory path for eliminating the door knock requirement, the result is estimated to be an additional $14.3 million benefit.

- Bad Debt - With advanced metering infrastructure, remote shut-off and insights into customer non-pay will enable NIPSCO to address customer non-pay situations more efficiently. By disconnecting power in a more timely manner, customers accrue a smaller unpaid bill (without higher fees) that they are more likely to pay. This minimizes the larger utility write-off that would have otherwise occurred. We are considering this to be a reduced expense benefit for the electric AMI business plan. With the existing door knock policy for non-pay, this benefit is reduced in the model in the base case scenario by a factor of 25%. NIPSCO’s current provision expense is $6.1 million with 61% of this attributable to electric. The model captures 25% of this benefit recovered and yields just under $8.0 million in total benefit.

- Outage Management – Through AMI insights there is a decrease in time needed to locate an outage. By considering the cost of outage restoration, the percentage of time spent locating an outage, and the amount of this locating time that feasibly can be reduced, a benefit can be estimated primarily driven through savings in labor time needed for the activity. A benefit is modeled by taking the total average outage restoration cost of $8.4 million per year and estimating that 15% of the time is spent locating an outage and that 50% of that can be reduced. This provides $9.7 million in modeled benefits. Furthermore, insights provided by AMI meter statuses and the pinging of meters increase outage management's ability to locate embedded outages, thereby reducing the triage time associated with power restoration in the field (not quantified in the model).

An additional benefit that is estimated in the model is the reduction in found-on instances that occur when a response is made to a customer call when there are indeed no service issues once an inspection occurs on location. It is modeled that only 50% of these truck rolls would go away due to certain customer calls still requiring a visit due to due to potential safety concerns. The benefit is calculated by considering the average number of non-outage/found-on truck rolls occurring annually (8,231) and the cost to respond to these events. In total, this benefit yields $11.7 million over the model timeframe including vehicle O&M savings.

- AMR Software and Licensing – There are currently ongoing O&M costs to NIPSCO through the maintenance of the AMR head-end system annual license, the mobile subscription for the optical probe, and for the FCS system that is utilized to sync AMR to billing. The FCS system requires software maintenance, software licensing, and other refresh/upgrade costs. It is modeled that these will go away as electric costs after electric AMI meter deployment is complete. This annual cost reduction results in $626,500 in benefit.

- AMR Meter Replacement Labor – It is expected that a higher number of AMR meters would fail annually than AMI meters initially due to the older asset life of existing AMR meters. Additionally, the AMI meter warranty covers AMI meter material costs for the first three years after deployment. Due to this, there will be a reduction in replacement labor costs incurred during the timeframe of the model on a net basis when comparing AMR to AMI. The result is $18.5 million in benefit.

4. NIPSCO Electric AMI Benefit – Customer Benefits

The Customer benefit of the AMI Project is estimated to be relatively large, totaling about half the total of the NIPSCO Operational benefits. The customer benefits described in this section are expressed in terms of reduced minutes of outage interruptions and electricity savings that result from behavior changes spurred on through usage data visibility.

Customer Benefits	Deployment Total	2027-2036 Average	2027-2036 Total	2021-2036 Total
Customer Electricity Savings	$231,152	$288,380	$2,883,795	$3,114,947
Customer Outage Benefit	$7,741,383	$8,786,221	$87,862,206	$95,603,590
Customer Benefit Total	**$7,972,535**	**$9,074,600**	**$90,746,002**	**$98,718,537**

- Reduced Customer Outage Minutes Benefit – This benefit category provides the largest customer benefit, and it is driven by a reduction in service interruption minutes during outage events throughout the year, a reduction enabled through insights from AMI data. The benefit was determined across NIPSCO customer types (residential, commercial, and industrial) using the cost to the customer per outage minute estimated utilizing NIPSCO data in the Interruption Cost Estimate (ICE) Calculator. The ICE Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory and Nexant, Inc.

Based on the NIPSCO's average 138 CAIDI metric, it was estimated as discussed above that 10% of the time responding to an outage is locating that outage. Assuming 50% of this can be reduced, this yields customers 6.9 minutes of fewer interrupted minutes due to outages. The ICE calculator offers two methodologies to calculate benefits: cost of outage minutes or value of improved reliability. The value of improved reliability produces a more conservative benefit estimate with similar inputs and provides an estimated 15-year benefit of $95.6 million.

- Customer Electricity Savings – Reductions in customer energy usage are expected and modeled for a subset of NIPSCO's customer base as a result of the proposed AMI implementation plan which integrates interval usage data to provide customer insights via the provided customer portal. To gauge the impact of customer utilization of the web portal, it is modeled that 10% of the residential customer base will make use of insights after full AMI deployment and will reduce their energy demand by 1.1%. Using the amount of an average customer bill without fixed charges, this yields $3.1 million total in electricity savings for the NIPSCO customers.

5. NIPSCO Electric AMI Benefit – Societal Benefits

The societal benefit of the AMI Project is projected to be large, but these benefits are not modeled to directly impact the net present value of the cost-benefits analysis. Instead, they are calculated to gauge the impact of the AMI program on NIPSCO customers and society as a whole. Modeled societal benefits include a reduction in GHG emissions and a positive impact on the economy. The benefit of reduced carbon dioxide emissions modeled results from lower electricity consumption due to customer electricity savings and reduced consumption on inactive meters. A reduction in emissions also comes from an overall decline in the NIPSCO service truck miles driven annually. The positive economic benefit of the AMI Project spend is calculated using available economic impact tools and the spend during the years of deployment (2021-2026).

Societal Benefits	Deployment Total	2027-2036 Average	2027-2036 Total	2021-2036 Total
GHG Emissions	$472,593	$473,459	$4,734,592	$5,207,185
Economic Benefit	$1,303,413,592	$0	$0	$1,303,413,592
Societal Total	**$1,303,886,185**	**$473,459**	**$4,734,592**	**$1,308,620,777**

- Carbon Dioxide Emissions – This benefit is a very small component of the societal benefits even with very generous assumptions on the value of reduced tons of carbon dioxide emissions. Contributions to emissions reductions are detailed below:

  - Avoided Power Plant Emissions – As stated above, it is modeled that customer utilization of the web portal will result in 10% of the residential customer base reducing total energy demand by 1.1% after AMI deployment. This would equate to approximately 4,287 MWh of energy reduced at steady-state and 47,250 MWh of energy reduced over the duration of the model. Based on an EIA metric, there are approximately 0.911 tons of CO_2 produced per MWh of electricity generated in the state of Indiana. Assuming this is a close approximation for the carbon intensity of the NIPSCO residential customer base, this would reduce electric sector emissions in the state of Indiana by 43,045 tons of CO_2. Additional emissions would be reduced through avoided consumption on inactive meters with the kWh reduction detailed in the related section above. This total contribution to this benefit is $4.9 million.

  - Avoided Vehicle Emissions – The reduction of CO_2 emissions that occurs from fewer truck miles driven as AMI enables automated activities is simply a calculation based on reduced vehicle mileage, the fuel economy of a representative truck per mile, and the carbon intensity of the fuel. Estimates were provided by NIPSCO for vehicle mileage per month for vehicles in the different organizations and estimates on vehicle mileage reduction yielded approximate carbon dioxide tonnage mitigated within each organization. Overall, this contributed $265,000 in benefits.

- Economic Benefit – This calculation was determined utilizing IMPLAN methodology which utilizes project capital spend categorized into representative categories of spend that have an associated economic multiplier. (This methodology is the same methodology used for the calculation of the economic impact benefit for the overall TDSIC plan.) The output describes the impact of capital spend in the United States, but it is also available for just that impact to the state of Indiana. The general idea is that the prolonged spend and influx of workers has benefit in the state/region/United State through necessary touchpoints with the local economy. Furthermore, job impacts also are calculated by the IMPLAN software application. The total economic impact across the United States is calculated to be $1.3 billion. Narrowing the view just to the state of Indiana, the total economic impact is calculated to be $490.2 million.

A summary of calculated benefits appears below:

Estimated NIPSCO AMI Project Benefits (2021-2036)

Avoided Capital Benefits	2021 Capital	2022 Capital	2023 Capital	2024 Capital	2025 Capital	2026 Capital	Deployment Total	2027-2036 Average	2027-2036 Total	2021-2036 Total
Vehicle Purchases	$0	$0	$0	$0	$632,500	$0	$632,500	$274,439	$2,744,392	$3,376,892
AMR Collector Hardware	$0	$0	$0	$0	$0	$0	$0	$103,500	$1,035,000	$1,035,000
Residential AMR Meter	$0	$0	$0	$57,637	$74,817	$67,567	$200,021	$268,930	$2,689,302	$2,889,323
Commercial AMR Meter	$0	$0	$0	$30,089	$39,599	$35,761	$105,449	$142,338	$1,423,376	$1,528,825
Avoided Capital Total	**$0**	**$0**	**$0**	**$87,727**	**$746,915**	**$103,329**	**$937,971**	**$789,207**	**$7,892,070**	**$8,830,040**
Additional Cost of Service Reduction Benefits	**2021 NIPSCO Cost of Service**	**2022 NIPSCO Cost of Service**	**2023 NIPSCO Cost of Service**	**2024 NIPSCO Cost of Service**	**2025 NIPSCO Cost of Service**	**2026 NIPSCO Cost of Service**	**Deployment Total**	**2027-2036 Average**	**2027-2036 Total**	**2021-2036 Total**
Theft	$0	$0	$0	$5,359	$274,279	$602,102	$881,740	$883,357	$8,833,566	$9,715,307
Consumption on Inactive Meters	$0	$0	$0	$12,901	$660,289	$1,449,479	$2,122,669	$2,126,560	$21,265,603	$23,388,273
Additional Cost of Service Reduction Total	**$0**	**$0**	**$0**	**$18,260**	**$934,569**	**$2,051,581**	**$3,004,410**	**$3,009,917**	**$30,099,170**	**$33,103,580**
O&M and Expense Reduction Benefits	**2021 O&M**	**2022 O&M**	**2023 O&M**	**2024 O&M**	**2025 O&M**	**2026 O&M**	**Deployment Total**	**2027-2036 Average**	**2027-2036 Total**	**2021-2036 Total**
Meter Reading	$0	$0	$0	$9,668	$509,676	$1,152,416	$1,671,760	$1,996,320	$19,963,204	$21,634,964
Meter Servicing	$0	$0	$0	$40,550	$2,234,529	$5,052,436	$7,327,515	$8,752,566	$87,525,660	$94,853,174
Outage Management	$0	$0	$0	$9,544	$503,146	$1,137,651	$1,650,341	$1,970,804	$19,708,044	$21,358,385
AMR Software and Licensing	$0	$0	$0	$0	$0	$0	$0	$62,646	$626,458	$626,458
Billing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Residential AMR Meter Replacement	$0	$0	$0	$191,732	$256,346	$238,452	$686,530	$1,131,361	$11,313,606	$12,000,136
Commercial AMR Meter Replacement	$0	$0	$0	$101,748	$137,958	$128,328	$368,034	$608,866	$6,088,655	$6,456,689
Bad Debt	$0	$0	$0	$4,391	$224,727	$493,325	$722,443	$723,767	$7,237,670	$7,960,113
O&M and Expense Reduction Total	**$0**	**$0**	**$0**	**$357,633**	**$3,866,383**	**$8,202,607**	**$12,426,623**	**$15,246,330**	**$152,463,295**	**$164,889,918**
Total NIPSCO Operational Benefits	**$0**	**$0**	**$0**	**$463,620**	**$5,547,867**	**$10,357,517**	**$16,369,003**	**$19,045,453**	**$190,454,535**	**$206,823,538**
Customer Benefits	**2021 Customer**	**2022 Customer**	**2023 Customer**	**2024 Customer**	**2025 Customer**	**2026 Customer**	**Deployment Total**	**2027-2036 Average**	**2027-2036 Total**	**2021-2036 Total**
Customer Electricity Savings	$0	$0	$0	$1,207	$63,116	$166,829	$231,152	$288,380	$2,883,795	$3,114,947
Customer Outage Benefit	$0	$0	$0	$0	$2,035,546	$5,705,837	$7,741,383	$8,786,221	$87,862,206	$95,603,590
Customer Benefit Total	**$0**	**$0**	**$0**	**$1,207**	**$2,098,662**	**$5,872,666**	**$7,972,535**	**$9,074,600**	**$90,746,002**	**$98,718,537**
Total Operational + Customer Benefits	**$0**	**$0**	**$0**	**$464,827**	**$7,646,529**	**$16,230,183**	**$24,341,538**	**$28,120,054**	**$281,200,536**	**$305,542,075**
Societal Benefits	**2021 Societal**	**2022 Societal**	**2023 Societal**	**2024 Societal**	**2025 Societal**	**2026 Societal**	**Deployment Total**	**2027-2036 Average**	**2027-2036 Total**	**2021-2036 Total**
GHG Emissions	$0	$0	$0	$2,872	$147,007	$322,713	$472,593	$473,459	$4,734,592	$5,207,185
Economic Benefit (Total Effect, Indiana Only)	$17,558,693	$49,360,676	$95,490,515	$119,765,702	$119,947,619	$88,088,724	$490,211,929	$0	$0	$490,211,929
Societal Total	**$17,558,693**	**$49,360,676**	**$95,490,515**	**$119,768,574**	**$120,094,626**	**$88,411,437**	**$490,684,522**	**$473,459**	**$4,734,592**	**$495,419,114**
Total Operational + Customer + Societal Benefits	**$17,558,693**	**$49,360,676**	**$95,490,515**	**$120,233,401**	**$127,741,155**	**$104,641,620**	**$515,026,060**	**$28,593,513**	**$285,935,129**	**$800,961,189**

6. Cost-Benefits Analysis (CBA) Summary

Total CBA costs and benefits are summarized in the figure below. O ver the entire project, it is estimated that NIPSCO would need to invest $172.6 million in total capital and $79.9 million in incremental cumulative expense, or operations and maintenance costs (O&M). These cost estimates go beyond just the cost of AMI meters and installation labor and detail a comprehensive list of necessary investments needed to enable the benefits detailed in this report. NIPSCO's analysis indicates total benefits, excluding societal benefits, of about $305.5 million over the 15-year period. On a nominal basis, modeled benefits exceed modeled costs by $53.1 million. Calculating the net present value of these cost and benefit streams indicates a -$14.2 million NPV, but this excludes the calculated societal benefits. When including societal benefits, while limiting the large estimated economic impact just to the state of Indiana, the AMI Project becomes an overwhelmingly positive NPV project, with the NPV rising to over $400 million. Beyond results directly impacting NIPSCO and customers, and societal benefits that would be realized through NIPSCO's investment in electric metering infrastructure, there are further opportunities for programs to be established that will provide value streams to NIPSCO customers and that are specifically enabled by the deployment of AMI.

Cost and Benefit Categories	2021	2022	2023	2024	2025	2026	**Deployment Totals (2021-2026)**	**Average Annual Post Deployment (2027-2036)**	**Post Deployment Totals (2027-2036)**	**Program Totals (2021-2036)**
Capital Cost (Indirect)	-$0.18	-$1.51	-$3.17	-$6.12	-$6.24	-$4.97	**-$22.19**	**-$0.06**	**-$0.61**	**-$22.81**
Capital Cost (Direct)	-$1.06	-$8.60	-$18.45	-$41.09	-$42.26	-$34.01	**-$145.47**	**-$0.43**	**-$4.33**	**-$149.81**
O&M Cost (One-Time Expense)	-$0.08	-$2.33	-$2.26	-$2.30	-$1.68	-$1.36	**-$10.01**	**$0.00**	**$0.00**	**-$10.01**
O&M Cost (Recurring)	$0.00	-$0.31	-$0.88	-$2.52	-$3.77	-$4.34	**-$11.81**	**-$5.80**	**-$58.04**	**-$69.86**
O&M and Expense Reduction Benefit	$0.00	$0.00	$0.00	$0.36	$3.87	$8.20	**$12.43**	**$15.25**	**$152.46**	**$164.89**
Avoided Capital Benefit	$0.00	$0.00	$0.00	$0.09	$0.75	$0.10	**$0.94**	**$0.79**	**$7.89**	**$8.83**
NIPSCO Cost of Service Reduction Benefit	$0.00	$0.00	$0.00	$0.02	$0.93	$2.05	**$3.00**	**$3.01**	**$30.10**	**$33.10**
Customer Benefit	$0.00	$0.00	$0.00	$0.00	$2.10	$5.87	**$7.97**	**$9.07**	**$90.75**	**$98.72**
Net Costs and Benefits (Nominal)	-$1.32	-$12.75	-$24.76	-$51.57	-$46.30	-$28.45	**-$165.15**	**$21.82**	**$218.21**	**$53.06**
Net Costs and Benefits (Real)	-$1.32	-$12.09	-$22.25	-$42.22	-$34.58	-$20.52	**-$132.97**	**$11.88**	**$118.79**	**-$14.18**

westMONROE perspective

AMI OBSOLESCENCE PERSPECTIVE

By: Danny Freeman, July 2019

As technology continues to evolve and Utilities are increasingly inclined to modernize their operations, it is important to understand the impact of today's technology decisions. Utility executives and regulators must continue to challenge their decision-making processes by understanding the risk of selecting the wrong technologies and/or those that will soon become obsolete. This mindset must also be balanced by the damage that can be done by not investing in needed, value-adding technologies that drive innovation and benefit realization for fear of what may be coming in the future that might be better.

While this balance of risk and reward can be complex and very difficult in some areas of emerging and cutting-edge technologies, one conclusion can be safely drawn by utility executives, regulators, and distribution grid operators alike: Advanced Metering Infrastructure (AMI) or "smart meters" are here to stay.

Though technically AMI and smart meter technology has been in place for many years, there are several factors that clearly demonstrate that premature obsolescence of this technology is not a concern, nor will it be in the near-term. These include:

- The state of AMI technology and deployment today
- Vendor technology trends, investment decisions, and market developments
- Feedback from third parties and industry re-searchers

With over 60% of the electric meters in the United States now being smart meters, and several new and planned projects for large smart meter deployment in various stages, the industry has established AMI as the preferred and standard metering technology.

Importantly, it is also clear that vendors and solution providers are doubling-down on their investments in AMI-centric products and offerings and continue to support these solutions for new and past deployments. In fact, most meter manufacturers have eliminated or significantly de-emphasized the large-scale production of the old, analog meter types that require walk-up and drive-by reads because of the limited demand and relevance of them in todays modernized electric utility environment. The industry has moved forward, and the main, foundational vehicle for that modernized future is AMI technology.

Detractors or skeptics of this conclusion and the long-term viability of AMI may point to Automated Meter Reading (AMR) technology as a reference point for a similar metering solution that was touted as the "next big thing" for utilities. It is true that AMR technology represented a significant change and upgrade in metering and operational capabilities. However it is important to recognize that while the AMR solution was impactful, value-adding, and cost-beneficial when compared to traditional metering ("walk-up" meters requiring individual manual reads), there were several factors indicating that the AMR technology was to become replaced in the near-term.

Researchers and meter manufacturers had already begun development and conceptualization of testing of AMI solutions as early as the 1980s. As cellular and other two-way technologies became more prevalent through the 1990's and 2000's, meter manufacturers and utility technology providers began investing in research and development of how broad deployment of two-way communicating networks could be applied to metering, and the value it would unlock across multiple benefit streams. This was happening while AMR solutions were being actively deployed. This is not to say that the decision to invest in and deploy AMR technology during this timeframe was poor or misguided. On the contrary, those investments have proven to deliver operational benefits and cost reductions that have placed a downward pressure on customer rates. In many cases, utilities that invested in AMR did so with "eyes wide open", knowing that a potentially superior solution was under development and would very likely be fully tested, viable, and widely deployed once the next metering decision cycle was upon them.

Another telling sign that AMR technology had the potential to be more of an interim operational solution is that it was not fundamentally transformational by nature. While the value of AMR is clear and the benefits (largely meter reading cost reductions) have exceeded the costs to deploy, it did not fundamentally change how a utility operated the grid nor how they interacted with customers. AMR metering still required manual reading, it was simply done more efficiently via a drive-by van rather than a meter reader walking up to each home. While this was a benefit, other operational improvements were not addressed by this technology, including the costs associated with manually cutting and restoring power and gathering and assessing meter and system health information for trouble shooting and other operational work order types. AMR meters did not improve a utility's ability to effectively identify or respond to power outages, nor did they assist in the identification of meter tampering and theft that led to safety concerns and additional costs socialized to all customers.

The technology did not enable two-way communication, and thus did not further enable broad deployment of customer programs, rates, or dynamic options that rely on metering when compared to what traditional meters could provide. The further enablement of distributed energy resources integration is also not enhanced with AMR. These factors and others also led to the fact that while AMR meters did represent a sizable component of the meter population in the United States, they were not adopted at the levels we see AMI adoption today and anywhere near what is projected moving forward. Nearly all major utilities operating on AMR technology have already transitioned to AMI or are in the process of doing so.

AMI technology, on the other hand, truly does change the game for utilities and their customers. From an operational perspective, by leveraging remote, two-way communication, AMI further reduced and essentially eliminated meter reading costs, while also enabling remote execution of work orders, most notably remote connect and disconnect which is a significant cost for utilities. Other work order types are also significantly reduced or eliminated due to the ability to remotely interrogate and assess operational conditions without the need to send a utility employee to that location.

Outage management capabilities of AMI are also significant and have been proven across the country. The ability to integrate AMI with Outage Management Systems enables utilities to significantly improve their outage response efforts while driving an improved customer experience through proactive outage identification (customers no longer need to call in to report outages) and restoration, and the delivery of updates to customers on the estimated restoration time and related information.

The customer experience is also dramatically improved during non-outage conditions as a result of AMI. By capturing interval energy usage data and enabling two-way capabilities such as pricing signals and demand response functionality, customers with AMI meters are empowered to take direct control of their usage, and participate in programs, rates, and communication channels that were not possible before. Real-time, two-way communication of interval usage data and other data points, when combined with advanced analytics solutions also allow utilities to identify a wide range of operating conditions, such as meter tampering and theft. This positions the utility to take swift action for resolution, significantly reducing related safety concerns and socialized costs to customers.

In summary, AMR technology made sense at the time, but its fundamental characteristics and other market activities demonstrated that it was likely a bridge to a more advanced solution rather than the new standard. That solution is AMI.

From strictly a meter perspective, the asset performance to date has been quite strong. Manufacturers commit to a useful life of 15 years with an estimated 95% of meters expected to be fully functional and in service after that period. Importantly, AMI meters are also fully programmable to ensure compatibility both backwards and forwards, as communications technology continues to adapt and change in the future. This means that as enhancements are made to other components of the technology landscape, remote programming and updating of meters can be done "over the air", thereby avoiding costly field visits and eliminating the need for meter replacement that would have been required with the prior generation of hardware. This includes important updates related to security controls and configurations.

From a telecommunication backhaul perspective, leading AMI vendors have committed to operating the LTE (4g mobile communications standard) network for the foreseeable future and are committed to aligning with new and evolving standards and requirements, while collaboratively developing specific and actionable plans for technology upgrades. These technology components prolong the useful life in ways that were simply not possible before, positioning utilities to operate a long-term, flexible, and dependable solution.

A wide range of research and analysis has been performed by industry third parties and other organizations to look into the risk of obsolescence for AMI technology. The consensus of these organizations, including the Electric Power Research Institute ("EPRI")[1], the National Institute of Standards and Technologies ("NIST")[2], and the North American Electrical Manufacturers Association ("NEMA") is that while the continued evolution of technology is difficult to predict, the risk of obsolescence of AMI is very low and can be effectively managed by specific processes, practices, and partnership with vendors and solution providers that are already in place.

EPRI has clearly laid out their guidelines for how utilities can ensure that their system is future-proofed, such as closely monitoring and measuring the performance of the network to ensure remote upgrades and updates and able to be executed. Additionally, they recommend that a reserve of system memory and performance capability be set aside for future changes and updates. EPRI also notes that the AMI software architecture should also be flexible enough to support multiple communications protocols to not limit its use with a particular technology, and to allow for additional types and quantities of data to be transported to and correctly interpreted with the system. Lastly, they note that AMI systems are secure and agile without needing to rely on frequent and broad hardware implementations, while still meeting the requirements and performance expectations. NEMA has communicated a set of requirements for smart meter upgradeability that inform how utilities can ensure that their solution is flexible and 'future-proofed' to align with ongoing innovation and improvement throughout the AMI value chain.

While the future of AMI as the standard appears certain, it is important that utilities keep close tabs on market trends and vendor activities. If the last decade of transformation in the utility landscape has taught us anything, it is that technology is changing very quickly and can be quite disruptive and impactful. That being said, at this point, unlike the position of AMR technology, there is an absence of any known or proven deployment of a new metering method or technology beyond AMI of any consequence. The transformative nature of the benefits of AMI, both qualitative and quantitative are simply too compelling to ignore. The technology is here to stay, and its foundational role in the context of broader grid modernization should not be ignored in lieu of an as yet identified, deployed, or validated future metering technology.

REFERENCES

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