FILED
May 14, 2019
INDIANA UTILITY
REGULATORY COMMISSION

I&M Exhibit: _____

Cause No. 45235

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

TOBY L. THOMAS

INDEX

**PRE-FILED VERIFIED DIRECT TESTIMONY OF TOBY L. THOMAS
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Toby L. Thomas, and my business address is Indiana Michigan Power Center, P.O. Box 60, Fort Wayne, Indiana 46801.

Q. By whom are you employed and in what capacity?

A. I am President and Chief Operating Officer of Indiana Michigan Power Company (I&M or Company).

Q. Please briefly describe your educational and professional background.

A. I hold a Bachelor of Science Degree in Mechanical Engineering from the Rose Hulman Institute of Technology. I joined American Electric Power Company, Inc. (AEP) in 2001 as a project engineer involved in the development and optimization of competitive power generation and industrial steam generation projects across the United States. I have performed various roles of increasing responsibility including serving as the Managing Director for Kentucky Power, Gas Turbine and Wind Generation. In 2013, I was named Vice-President Competitive Generation for AEP Generation Resources, where I was responsible for the safe, efficient, and environmentally compliant operation of AEP's competitive generating assets – i.e., the AEP plants that are not part of a vertically integrated AEP operating company. I became President and Chief Operating Officer of I&M on January 1, 2017.

Q. What are your principal areas of responsibility with I&M?

A. I am responsible for the safe, reliable, and efficient day-to-day operation of I&M, which is an operating company subsidiary of AEP. I am accountable and responsible for I&M's financial performance and the quality of the services we provide to our customers. My responsibilities include I&M's community involvement and economic development, and ensuring compliance with federal regulatory and statutory rules, as well as laws of Indiana and Michigan, the states comprising the Company's electric service territory. Essentially, I am accountable for the Company's distribution, customer service, transmission, and generation functions to provide safe, adequate and reliable service to I&M's customers.

Q. Have you previously testified in any regulatory proceedings?

A. Yes. I provided testimony in I&M's last rate case before the Indiana Utility Regulatory Commission (IURC or Commission) docketed as Cause No. 44967. I also provided testimony in Michigan Public Service Commission (MPSC) Case No. U-18092. I also testified before the Public Utilities Commission of Ohio in Case Nos. 14-1693-EL-RDR et seq. on behalf of Ohio Power Company.

II. <u>PURPOSE OF TESTIMONY</u>

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

A. My testimony provides an overview of I&M's overall request that the Commission approve a total annual increase in revenues of approximately $172 million, or 11.75%. The Company proposes to phase the increase in over three steps; the initial step will reflect an increase of $82.5 million, or 5.63%.

My testimony describes the challenges I&M and its customers face in a changing world and I&M's ongoing efforts to provide service to customers. I will discuss how I&M is making significant capital investments to maintain and enhance our generation and energy delivery facilities to meet the needs and expectations of our customers. We are addressing the need to replace aging infrastructure, strengthen the grid, and redesign our rates in the face of technological change.

In particular, I will discuss our plans to deploy Advanced Metering Infrastructure (AMI) as an essential element of evolving our business so that it is capable of effectively serving customers who have alternatives to our service. My testimony also discusses the efforts I&M is making to control costs, grow its business, and keep the bills of our customers just and reasonable. We at I&M have a responsibility to our customers to manage our business properly so I ask the Commission to timely approve the proposed rate relief to allow I&M to continue to provide customers adequate and reliable electric service and facilities.

Q. Are you sponsoring any Attachments in this proceeding?

A. Yes. I am sponsoring the following Attachments:

- Attachment TLT-1, which is a copy of the Petition in this Cause (and is not separately reproduced with my testimony);
- Attachment TLT-2, which is an index of witnesses supporting I&M's filing; and
- Attachment TLT-3, which is the Rockport Ownership Diagram.
- Attachment TLT-4, which is a copy of the 2017 IEE report identified below.

Q. Were the Attachments that you are sponsoring prepared by you or under your direction?

A. Yes.

III. <u>I&M OVERVIEW</u>

Q. Please describe I&M and its organizational structure.

A. I&M supplies electric service to approximately 468,000 retail customers in northern and east-central Indiana and 129,000 retail customers in southwestern Michigan. I&M operates plant and equipment in Indiana and Michigan that are in service and used and useful in the generation, transmission, and distribution of electric service to the public.

The Company's principal offices are located in Fort Wayne, Indiana. I&M's four distribution and customer service districts (Benton Harbor, Fort Wayne, South Bend/Elkhart, and Muncie/Marion) are each responsible for a specific geographic portion of I&M's service territory.

I&M is subject to the regulatory authority of the Indiana Utility Regulatory Commission (IURC or Commission), the Michigan Public Service Commission (MPSC), and the Federal Energy Regulatory Commission (FERC). I&M is a member of PJM Interconnection, LLC (PJM), which is a regional transmission organization (RTO) serving the eastern portion of the country.

Q. Please provide an overview of the Company's generating resources.

A. I&M's generating fleet includes two major generating plants: the two unit, 2278 megawatt (MW) Cook Nuclear Plant in Bridgman, Michigan and the two unit, 2620 MW coal-fired Rockport Plant in Spencer County, Indiana.[1] I&M purchases 450 MW of wind energy from three wind farms located in Indiana. I&M also owns and operates 14.7 MW[2] of universal solar power sites consisting of four sites. I&M's fleet also includes six small hydroelectric plants comprising 22.4 MW on the St. Joseph River in southwestern Michigan and northern Indiana. The hydroelectric plants consistently produce, on average, approximately 100,000 MWH of emission-free renewable energy annually. This results in a Test Year end generation resource mix as shown on Figure TLT-1:

Figure TLT-1
I&M Test Year End Generation Resource Mix[3]

Nuclear	Solar	Hydro	Wind	Coal
44.1%	0.3%	0.4%	8.7%	46.5%
2,278MW	14.7MW	22.4MW	450MW	2,402 MW
Cook Unit 1 Cook Unit 2	Four Solar Plants	Six Run-of-River Hydroelectric Dams	Wildcat Headwaters Fowler Ridge	Rockport 1 Rockport 2 OVEC[4]

Q. Please describe I&M's Indiana service territory.

A. I&M's Indiana service territory consists of over 3,200 square miles and includes the Cities of Fort Wayne, South Bend, Elkhart, Muncie, Marion, Kendallville and Decatur. In addition, I&M's Indiana service territory consists of approximately

[1] These MW ratings are all nominal. I&M owns 50% of Rockport Unit 1 and leases 50% of Rockport Unit 2 under a sale and leaseback arrangement. I&M also purchases 35% of the capacity and energy of Rockport 1 and 2 from AEP Generating Company (AEG) under a FERC filed Unit Power Agreement. In total, through these arrangements 2227 MWs of the combined 2620 MWs of the Rockport Plant is available to serve I&M customers. Please refer to Attachment TLT-3 for a graphical depiction of the Rockport arrangements.

[2] References to solar capacity in MW are in alternating current (AC).

[3] This table does not include a 20 MW solar facility that I&M will be seeking approval of in a separate filing.

[4] Ohio Valley Electric Corporation, which is subject to FERC regulation, was formed in 1952. OVEC and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation, own and operate the Kyger Creek Power Plant, located at Cheshire, Ohio and the Clifty Creek Power Plant near Madison, Indiana. These generating stations, which began operation in 1955, have long contributed to I&M's resource mix.

4300 circuit miles of transmission facilities and more than 15,100 miles of distribution lines and general plant facilities. I&M's energy delivery system is discussed in further detail by Company witness Isaacson.

At the time this case is filed, I&M provides wholesale electric service to the Wabash Valley Power Authority, Indiana Municipal Power Association (IMPA), the City of Auburn, and the Indiana Michigan Municipal Distributors Association (IMMDA).[5] However, all but one of the contracts with IMMDA members (comprising approximately 300 MW) will expire on or before June 1, 2020. (The last contract will expire on or before June 1, 2026).

Q. Please describe the relationship between AEP and I&M.

A. AEP owns electric operating companies located in the Midwestern and central parts of the country, including I&M. In key respects, the operating companies function as an integrated utility system that provides electric service to 5.4 million customers located in eleven states. To effectively manage the costs of joint activities, American Electric Power Service Corp. (AEPSC) provides corporate support services to the operating companies, including generation-related services, human resources, accounting, finance and legal.

I&M is located in the AEP System – East Zone (AEP East), which is an integrated generation and transmission network located in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. AEP's operating companies, including I&M, are responsible for day-to-day operations and

[5] The IMMDA consists of Avilla, Bluffton, Garrett, Mishawaka, New Carlisle, and Warren, Indiana, and Dowagiac, Niles, Paw Paw, South Haven and Sturgis, Michigan.

management of local business affairs, including responsibility and accountability for the operation of each operating company's generating plants.

I&M participates in a FERC-approved Power Coordination Agreement (PCA) with the two other regulated, vertically-integrated AEP East Operating Companies (Appalachian Power Company and Kentucky Power Company). The PCA is the successor agreement to the AEP Interconnection Agreement that terminated in January 2014. Through the PCA, I&M is essentially a stand-alone entity for purposes of planning for and ultimately achieving its customers' capacity and energy resource needs. The PCA also provides for the direct assignment of traditional Off System Sales (OSS) and for the allocation of asset hedges and trading.

IV. ONGOING CHALLENGES AND SERVICE TO CUSTOMERS

Q. Please describe the ongoing challenges faced by the Company with respect to the ongoing provision of adequate and reliable retail electric service and facilities.

A. The key challenges facing I&M include how to continue to provide reliable electric service at a comparatively low price when costs are rising, customer needs are changing, technology is rapidly evolving, and environmental regulation remains uncertain. The ability to recover our costs in a timely manner also remains important to the financial health of the Company.

In today's digital world, the many electronic devices and equipment used by our customers are less tolerant of even minor service interruptions. This requires increasing diligence with respect to service reliability. We also continue to need to recognize evolving environmental requirements, including policies that address the issues surrounding climate change. Importantly, we must recognize and adjust to the impact of technological change that enables customers to self-generate and the reduced cost of renewable energy.

At the same time, deploying technology as part of our infrastructure can change how our customers use electricity and improve the way we operate our systems. In other words, as technology advances, the electric industry has the opportunity to enhance the way it does business to benefit both customers and companies. In this case, we are focused on expanding our use of technology and automated controls to improve our energy delivery infrastructure and service. Doing so allows us to meet our customers' ongoing need for electricity and serve them in the way they want to be served. The Company's proposal regarding AMI is a key example of how we can use today's technology to meet customer needs for service.

Q. Is the timely recognition in rates of the costs incurred to serve customers important to the Company and its customers?

A. Yes. First, I&M's financial performance can be adversely affected by the difference between the time the Company makes an investment or incurs an operating cost and the time such costs are recognized for ratemaking purposes. In the past, regulators and companies were able to rely on increasing kWh sales to mitigate, at least in part, the impact of lapse between the time an investment is made and the time when it is recognized in rates. We now operate in a world of flat or declining load and no longer have the ability to rely on load growth to absorb cost increases.

The reality is that I&M's kWh sales will continue to be relatively flat for the foreseeable future due to technological change, energy efficiency standards and behind-the-meter energy options. I&M has worked hard to responsibly grow our business by attracting and retaining customers and we are even more committed to supporting the economic development of the communities in which we serve. We are also expanding our efforts to create a "plug and play" platform that facilitates expansion of electric vehicle charging technology in a way that allows all customers to benefit.

Second, I&M's financial performance can be adversely affected if rates do not produce the level of revenue they were designed to produce. If customers are sent incorrect price signals that do not properly reflect the predominately fixed cost nature of our business, they will choose suboptimal alternatives that will erode revenues needed to support the operation of the grid. In the face of ongoing technical change, it is imperative that the design of our rates does not over time create unwarranted cost shifts from one set of customers to another. We must improve our rate design to address the impact of distributed energy resources and to send appropriate price signals to our customers.

Q. Please comment on the importance of designing rates appropriately to address the impact of distributed energy resources on the Company and its customers.

A. Our customers, both retail and wholesale, have options and alternatives to our service, such as where they locate and whether to use distributed generation, such as solar or combined heat and power. The ongoing availability of low cost natural gas, as well as the reduced cost of renewable energy technology, provides a real opportunity to customers to generate their own electricity behind the meter. While technological advancements and having alternatives can be a positive, it is nonetheless a dramatic change that companies, customers and regulators should recognize and manage in a way that benefits all concerned.

It is important to recognize this in setting rates because not doing so can adversely affect the Company and our remaining customers. For example, a customer who uses distributed generation at their home can reduce the volume of electricity the customer needs from I&M. But, self-generation does not avoid the need for the home to be connected to and use the grid. Nor does it eliminate the need for the Company to be ready with generating capacity and energy to serve the home when the customer's distributed generation equipment is not available. Cost recovery is particularly distorted in this scenario[6] for residential customers because today's residential rate structure recovers most of our fixed cost of providing service through the volumetric kWh charge. Costs are inappropriately shifted to other customers who are not in a position to self-generate.

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[6] A similar situation exists with respect to residential customers who use less electricity because they leave the service territory in cold winter months or hot summer months.

The costs of providing service are not appropriately recovered from all customers in these examples because our existing rates are designed to recover much of the fixed cost of service through the volumetric rates despite the fact that our fixed cost of service does not vary with the amount of electricity used. In our last general rate case, we began a gradual transition away from this kind of rate structure because it inappropriately shifts costs and sends inaccurate price signals. In this case, we propose to again improve our rate design.

Q. Are the proposals to design rates and responsibly grow load important objectives?

A. Yes. The Company's package of base rates and rate adjustment mechanisms are important if the Company is going to continue to be successful in meeting our customers' needs for reliable and innovative service at a comparatively low cost.

As discussed above, we can and should continue our efforts to establish rates based on cost causation principles and to transition to a rate design that more accurately reflects the fixed and variable cost of the service we provide. That way, customers who may choose to reduce their individual volume of electricity usage through self-generation will not shift their cost of service to the remaining customers who choose not to.

I&M strives to maintain competitive rates and reliable service to attract and retain customers. We must also continue our efforts to maintain electric load by continuing to support economic development in our service area. Economic development remains vitally important to our communities and all of our customers and Company witness Lucas addresses the Company's proposals in this case to continue our support of economic development. As discussed by Company witness Lehman, the developing market for electric vehicles provides another opportunity to improve the Company's load and load shape. If we can integrate this load efficiently, all customers benefit.

Q. Is it important to continue the use of general rate cases in combination with ongoing rate adjustment mechanisms?

A. Yes. We appreciate the ability to use a forward-looking Test Year and the Commission's approval of timely cost recovery mechanisms for environmental costs, energy efficiency, purchased power (including wind and solar energy), and PJM costs, as well as our ongoing investment in Cook and Rockport Plants. These rate adjustment mechanisms encourage investors and enable projects to be funded at a reasonable cost of capital. As shown by Company witness Ali, the PJM Rider is particularly important due to the increasing cost of transmission service within PJM. I&M seeks to continue the timely recovery of costs because the proposed rate adjustment mechanisms are an important tool in our effort to meet these and other ongoing challenges while providing reliable service to our customers.

V. OVERVIEW OF I&M'S REQUEST

Q. What is the annual revenue increase sought by I&M in this proceeding?

A. As noted above, I&M is requesting that the Commission approve a total annual increase in revenues of approximately $172 million, or 11.75%, based on a forward looking calendar Test Year ending December 31, 2020. This is the amount that would be effective commencing with step 3 of the phase-in plan.

The Company's request is supported by the witnesses identified on Attachment TLT-2. This support includes testimony and evidence from subject matter experts, including subject matter experts responsible for providing generation and energy delivery services. This support also includes testimony of financial experts to discuss the financial condition and needs of the Company and technical witnesses to describe the level of costs and revenues going forward.

Company witness Williamson summarizes I&M's requested rate relief, and together with the Company's other witnesses supports the accounting and ratemaking reflected in the Company's filing. Company witness Nollenberger supports our proposed rate design, including the proposed changes in the residential rate design.

Q. When were I&M's current basic rates and charges established?

A. I&M's current basic rates and charges were established by the March 30, 2018 Commission Order approving the Settlement Agreement in Cause No. 44967. Accordingly, this petition is being filed more than 15 months after the filing of the petition in I&M's last rate review.

Q. Why is the requested rate increase necessary?

A. As a regulated company, the price the Company charges for retail electric service is necessarily underpinned by the cost the Company incurs to provide service. The costs used to set the revenue requirement in our last rate review have changed such that that revenue requirement is no longer sufficient to cover the Company's cost of providing service. As shown by the Company's case-in-chief, the Test Year results demonstrate that the Company's rates will no longer be just and reasonable.

Q. Please describe some of the key changes underlying the need to adjust rates.

A. Some of the key changes include the termination of wholesale contracts that contributed revenues used to reduce the retail revenue requirement. Additionally, there have been changes in I&M's depreciation rates and nuclear decommissioning expenses.

Another key change underlying the need to adjust rates includes average annual capital expenditure of $616 million during the Capital Forecast Period (January 2019 – December 2020).[7] This investment is made to serve customers, recognize innovations that are underway to automate and enhance the reliability of I&M's service, and comply with environmental requirements, including Section 316b of the Clean Water Act and the Federal Consent Decree governing the Rockport Plant (Consent Decree).

The investments reflected in the Company's filing, including projects at the Cook Nuclear Plant and the Rockport Plant, and the deployment of AMI, are necessary to allow the Company to meet the ongoing need for service and facilities and to continue to build the foundation for ongoing technological advancement and evolving customer service needs. As discussed by Company witness Lucas, I&M's capital investment strategy continues to be focused on infrastructure improvements,

[7] I&M Company witness Lucas, p. 14.

environmental and regulatory compliance (including cyber security and physical security of assets), technology innovation, and an improved customer experience.

Q. Please provide an overview of the ongoing investment in the Cook Plant.

A. The Cook Plant remains an important part of the Company's generation fleet and the Company continues to invest in these two emission-free units so that they will be able to operate through their 2034 and 2037 license lives. To achieve this objective, the total forecasted amount of capital expenditures for the Cook Plant to be placed in service during the Capital Forecast Period (January 1, 2019 – December 30, 2020) is approximately $478 million. See Company witness Lies Figure QSL-2. This includes our ongoing investment in the Life Cycle Management (LCM) Project approved by the Commission in Cause No. 44182. Company witness Lies discusses the Company's substantial progress on the LCM Project and Company witness Williamson describes the Company's proposed treatment of LCM costs and the ongoing operation of the LCM Rider as we move to the completion of the LCM Project in 2022.

Q. Please provide an overview of the Enhanced DSI Project at the Rockport Plant.

A. Both units of the Rockport Plant are equipped with flue gas scrubbing technology that uses Dry Sorbent Injection (DSI) equipment to inject dry sorbent (sodium bicarbonate) into the flue stream to reduce hydrochloric acid (HCl) and sulfur dioxide (SO_2) emissions. The Enhanced DSI Project at the Rockport Plant will enhance the performance of the DSI equipment by moving the injection point of the sodium bicarbonate into the flue gas stream upstream of its current location.

I&M's 50% share of the total project cost is estimated to be $13.3 million and its 50% share of the total incremental annual O&M costs is expected to be $8 million.[8] Company witness Tim Kerns describes the project in more detail in his testimony and Company witness Andrew Williamson discusses the rate adjustments.

Q. Why is the Enhanced DSI Project reasonable and necessary?

A. The Enhanced DSI Project is anticipated to be necessary to comply with the provisions of the Fifth Modification of the Consent Decree. As the Commission is aware from prior cases involving the Consent Decree, AEP entered into the Consent Decree to resolve the allegations filed against AEP and its affiliates (including I&M) related to the New Source Review (NSR) provisions of the Clean Air Act (CAA). As reflected in the agreement, AEP and I&M vigorously contested the allegations brought against it and did not agree that its actions violated the NSR rules. The NSR litigation campaign against AEP and virtually every other large coal-fired generating utility in the country constituted a new form of regulation by EPA designed to require further emission reductions from coal-fired generating plants. As reflected in the agreement, the Consent Decree was entered without any admission by AEP, and without any adjudication of the violations alleged in the complaints. AEP entered into the Consent Decree because it was a reasonable means of resolving lengthy and expensive litigation that could have resulted in substantially higher costs and rates for I&M and its customers.

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[8] See Company witness Kerns, pp. 30-31.

The Consent Decree took effect on December 10, 2007 and has been modified several times. At one point, I&M was moving forward with the installation and operation of a $1.4 billion dry scrubber on Rockport Unit 1 while it continued to investigate alternative means of meeting its Consent Decree requirements. As a result, I&M and the parties to the Consent Decree were able to agree to the Third Modification, which, among other things, revised the requirements to retrofit Flue Gas Desulfurization (FGD) equipment on Rockport Unit 1 and Rockport Unit 2. Specifically, the Third Modification recognized the installation and operation of the DSI equipment as satisfying the near-term obligations for the Rockport Plant. The cost of the DSI equipment installed on both units was estimated to be approximately $280 million, which is significantly less than the cost of a dry scrubber.

I&M's President at the time, Paul Chodak, in testimony to the Commission stated:

> **[T]he cost of installing DSI is the optimal near-term solution and allows I&M to continue to evaluate the cost-effectiveness of future investments as we gain more certainty about future environmental requirements.[9]**

As indicated by Mr. Chodak, I&M has continued to evaluate investments that would be a cost effective means of meeting environmental requirements. After a thorough investigation, I&M determined that there was an innovative approach that could allow it to achieve the same environmental benefits of the Third Modification in a more cost-effective manner. A key component of that

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[9] IURC Cause No. 44331, Chodak Direct Testimony at 12-13.

alternative approach was to enhance the effectiveness of the DSI equipment already in place.

After extensive and lengthy discussion and negotiations with the parties to the Consent Decree, the parties reached an agreement in principle that would, among other things, avoid the requirement to install dry scrubbers on both Rockport Unit 1 and Rockport Unit 2, which installations may have otherwise occurred in 2025 and 2028. The parties have advised the presiding Federal Judge that they have reached an agreement in principle, which would be the Fifth Modification of the Consent Decree.[10] I&M expects that agreement will be signed and filed with the Federal Court soon. If approved by the Federal Court, it would require the installation and operation of the Enhanced DSI Project on Rockport Unit 2 by June 1, 2020 and Rockport Unit 1 by December 31, 2020.

The cost to install the Enhanced DSI Project is estimated to be approximately $13 million, which is significantly less than the cost of a dry scrubber. As such, the Fifth Modification of the Consent Decree, if approved by the Federal Court, would allow I&M to move forward with complying with environmental requirements and significantly reduce the uncertainties regarding the Rockport Plant. This, in turn, will benefit customers by achieving these results by making a relatively small investment to enhance the existing DSI equipment.

In summary, the Enhanced DSI Project is a reasonable means of maintaining the availability of relatively low cost, coal-fired generation that complies with environmental regulations, allows the plant to continue to serve customer

[10] The Fourth Modification to the Consent Decree did not substantively affect the requirements of the Third Modification.

needs, provide jobs and taxes to the community, and does so in a manner that mitigates the rate impact on customers.

VI. <u>ADVANCED METERING INFRASTRUCTURE</u>

Q. Please summarize the Company's AMI deployment plan.

A. During the Test Year in the current case, the Company will begin the initial phase of AMI deployment. The proposed three year AMI deployment will continue through 2022. As also discussed by Company witness Williamson, the estimated capital cost of the total AMI Project over this three-year period is approximately $93.6 million.

Q. Please summarize the relief sought for the AMI Project.

A. I&M requests the Commission to approve the three-year AMI deployment project, authorize timely cost recovery through the AMI Rider presented by Company witness Williamson, and approve Company witness Cash's proposal regarding meter depreciation. Company witness Cooper discusses the Company's AMI opt-out tariff provision that will allow a customer to opt out, or decline, the use of this AMI meter and instead be served through a Radio Frequency (RF) meter. Our experience with AMI technology indicates that the percentage of customers who seek opt out will be small and this provision reasonably accommodates this customer segment.

Q. Please provide a description of AMI.

A. At a high level, AMI refers to systems that measure, collect, and analyze data from the distribution system, on a near real-time basis, from all meters through a communications network. This infrastructure includes hardware, such as meters that enable two-way communications (AMI meter), the communications network, customer information systems, and meter data management systems.

AMI is also referred to as “smart grid” or “smart metering”. The meters are “smart” because they enable two-way communication between the meter and the utility’s central systems. Smart meters can record consumption of electric energy and demand, and system parameters such as voltage at intervals of an hour or less and can digitally communicate that information to the utility. This enables the utility to have more accurate information about system operating conditions for operation and planning purposes as well as electricity usage to provide timely information to customers.

The AMI infrastructure comes with a customer engagement platform that enables the consumer to have better insight into the consumer’s electricity usage and cost. In other words, through the platform, the customer can see how much energy the customer is using at different times of the day, week, month or year, and this in turn can help the customer manage electricity usage and bills by highlighting ways the customer can be more energy efficient.

As discussed by Company witness Lucas, from a customer perspective, the customer engagement platform is the vehicle that unlocks the power of having access to the data that AMI provides. The level of integration required to provide this platform is very extensive and requires a significant upfront investment to build out, but the benefit to customers of being able to use this information to make better decisions about their electric consumption habits and manage their monthly budgets will be recognized for many years into the future.

Q Is AMI a reasonable and necessary investment for the provision of electric utility service?

A. Yes. As technology advances, the electric utility industry must enhance the way it does business to achieve both system and customer benefits. I&M's plan is to provide a robust energy delivery system that is both reliable and efficient (and can accommodate two-way power flows with increased distributed energy resources), and ultimately a platform which enables universal access to all customers to be served the way they want to be served – all at a reasonable cost.

In our last rate review, I discussed the benefits of AMI and the Company's effort to prepare to fully integrate this technology. In this current case, we explain our proposed deployment of AMI systems. Company witness Isaacson discusses the AMI project from an operational standpoint. Company witness Lucas explains how the AMI technology will provide access to data that I&M will use to educate and better position customers to make informed decisions regarding their energy usage. This general rate case is necessary to support the Company's effort to take advantage of AMI technology, which in turn will lay the foundation for a customer-facing, innovative energy grid.

Q. Why is the Company pursuing AMI deployment at this time?

A. Ever since AMI emerged, the Company has monitored the development of smart infrastructure, exploring its potential use and assessing how and when to move forward with AMI deployment. Ten years ago, I&M conducted a Smart Meter Pilot Program (SMPP) in collaboration with the Indiana Office of Utility Consumer Counselor (OUCC) (Cause No. 43607). The SMPP was designed to develop, implement and measure the potential benefits of smart grid technologies and programs through the deployment of approximately 10,000 two-way smart meters and associated infrastructure to test this technology with residential and commercial customers. While the pilot provided substantial information regarding AMI and its use, it also showed that the technology was still in its infancy and that customers were not ready to put the technology to use. Accordingly, the Company reasonably decided to wait for the technology to mature.

AMI technology has now matured as expected and customers have become accustomed to digital technology and real time access to data. Customers expect energy companies to provide them with proven technology that can make their experience better. We can improve our service to them by modernizing the grid and enhance their use of our service by developing innovative products and services.

Moreover, our AMR meters are at the point where they are in need of replacing. Given the age of the existing meters, we considered whether to continue to replace failing meters with AMR or move to the next generation of technology. In making our decision, we recognized that over the past decade AMI technology has matured, its pricing has stabilized and its importance to system reliability has increased.

The Commission has previously encouraged electric utilities to examine smart technologies and demand response opportunities. In Indiana and across the country, companies have already transitioned to AMI and we likewise have the responsibility to maintain our facilities in a state of efficiency corresponding to the progress of the industry. These days, the normal course of business requires companies to thoughtfully determine when to move from one generation of technology to the next to keep up with the pace of technology.

Our experience and knowledge of AMI technology tells us that investing in that technology can provide many benefits to the distribution system and our customers and that we have reached the appropriate time for deployment of AMI in I&M's service area. Consumer demand for services reliant on two-way communications has also evolved and I&M can take advantage of the lessons learned from AMI deployment by our AEP affiliated operating companies in other states. Taken together, all of these factors support the proactive move to AMI at this time.

Q. Why is it appropriate to deploy AMI over a three-year period?

A. Three years are reasonably necessary to efficiently and cost-effectively obtain the necessary resources for the project, install the technology and IT systems, and implement the associated consumer education and functionality. A period of less than three years is not sufficient to accomplish the full scope of I&M's AMI deployment proposal in this case. A longer deployment period is not desirable because a mixture of AMI and AMR meters in an area is less efficient. In addition, a longer period would decrease the efficiency of the roll out and delay the operational and customer benefits we are seeking to achieve.

Q. Please discuss the importance of AMI to system reliability and innovation.

A. The electric industry is in a time of exponential change. AMI technology is a foundational part of ensuring system reliability as we transition to distributed energy resources (DERs) and will better enable customers to adopt and optimize DERs ‘at scale’. The more distributed the generation and storage assets, the more granularity the utility needs to safely and reliably run the system both real time (second to second), day ahead (forecasting what will happen to ensure sufficient resources are available), and long term (what needs to be built and where, by circuit) to ensure it all works seamlessly to the users of the system. The grid is simply too critical to everyday life and national security to not use available and proven technology to optimize and protect it.

Furthermore, technology enables innovation. Improved distribution system insight is needed now to better optimize not only today’s system performance (including critical times such as storm restoration), but system investments. We are investing in our system both now and into the future - this improved insight is available through AMI. This investment furthers our commitment to invest wisely to serve our customers.

AMI also provides customers more insight into how and when they use the electric service. At a time when we are making prudent investments to continue safe and reliable service, costs are necessarily increasing due to those investments. Insight allows each customer to have the best control of their situation by adjusting usage, optimizing available programs, etc. Customers want transparency, insight, and control and AMI is a critical piece of enabling just that.

Q Is there other information that I&M considered when deciding whether to move forward with deploying AMI?

A. Yes, we are aware that the industry is moving to AMI. The appropriateness of moving to AMI is reinforced by a recent reports published by The Edison Foundation Institute for Electric Innovation (IEE) titled Electric Company Smart Meter Deployments: Foundation for a Smart Grid (October 2016 and December 2017) and information available of the Commission's website. The IEE reports are publicly available on the Internet and I have included a copy of this 2017 Report with my testimony as Attachment TLT-4.

The IEE report shows that smart meter installations have grown dramatically since 2007. The smart meter installations and projected deployments compiled in the reports reflect millions of AMI meters installed, primarily in other states. For example, the report states that smart meters covered more than 55% of U.S. households in 2016 and deployment is projected to increase from 72 million smart meters deployed in 2016 to 90 million by 2020.

While the 2016 report showed Indiana was behind other states in households with smart meters, the later report reflects that further progress has been made in Indiana. The Indiana results include the approximately 10,000 meters I&M deployed as part of our SMPP, approximately 53,000 meters installed by 2016 by Indianapolis Power & Light Company, and nearly 548,000 meters installed by Indiana public power utilities and cooperatives. The 2017 report acknowledges that AMI deployment in Indiana by Duke and Vectren is underway. This information helped I&M confirm that the Company's proposed deployment of AMI is consistent with activity across our state and nation.

Indiana also recognizes the value of AMI to Integrated Resource Plans (IRP). For example, the December 27, 2018 Report for the 2017 Integrated Resource Plans submitted by Hoosier Energy, Indiana Municipal Power Agency and Wabash Valley Power Association issued by Dr. Bradley Borum, the IURC Electricity Director, states (p. 11):

> **The members of these three utilities are in various stages of installation various stages of installing Advanced Metering Infrastructure (AMI), which provides the opportunity to develop customer specific data to facilitate enhanced load forecasting, DSM, and Distributed Energy Resources (DER) analysis. The Director recognizes that all utilities are struggling with how to use this type of data and that these utilities' organizational structures limit their abilities to coordinate with their members the collection of even the most basic data, such as billing data, for end-use customers and customer surveys for all types of customers. However, load forecasting, DSM, and long-term resource planning is hampered without greater coordination in data and analysis. As DER and other innovative technologies achieve greater penetration, the lack of coordinated data may frustrate attempts to understand the ramifications for their respective systems. [footnote omitted**]

The Director's August 30, 2016 Report on I&M's last IRP (p. 12) also pointed out the value to be gained from AMI infrastructure:

> **To I&M's credit, they recognized that technologies such as Smart Grid and Advanced Metering Infrastructure (AMI) would provide enormous data for load forecasting and DSM analysis. I&M states, "an expansion of AMI was not considered within the context of this IRP. I&M recognizes that sub-hourly data may help inform the load forecasting process relied upon in IRP modeling, especially in DR [Demand Response] applications" (page 7 of I&M's response).**

While the timing and nature of the Company's decisions regarding infrastructure are necessarily Company specific and dependent on circumstances in our service territory, these materials illuminate and validate the Company's plan to deploy AMI over the next three years.

Q. Please discuss the benefits of AMI.

A. As stated in my testimony in Cause No. 44967, AMI benefits both the distribution system and customers. I&M's sister companies have moved to this technology and utilities across the U.S. have reported strong acceptance of Smart Grid technology.

The transition to "Smart" technologies enables a fundamental change in the way we operate, serving as the necessary foundation upon which we will provide more reliable service, improved customer experience and greater efficiency opportunities for our customers in the future. More specifically, the utility operations and customer benefits from the proposed AMI deployment include:

- Increased efficiency of meter operations.
- Improved employee and public safety.

- Reduced environmental impact.
- Improved meter accuracy.
- Improved data for billing and operations.
- Improved power outage detection.
- Automation of service connection, disconnection and reconnection.
- Remote meter reads on demand.
- Improved credit/collections.
- Improved service restoration, outage detection and service reliability.
- Improved Theft and Tampering detection.
- Reduced Call Center Activities.
- Quicker processing of customer requests.
- Improved Customer Experience.

These benefits are further illustrated by Attachment TLT-4 and are also discussed in the testimony of Company witnesses Isaacson and Lucas.

VII. EFFORTS TO MITIGATE INCREASING COSTS

Q. Please discuss the ongoing efforts taken by I&M to manage costs.

A. The Company is keenly focused on maximizing the value of the service we provide to our customers. One way we seek to achieve this is by mitigating cost increases where possible without negatively impacting service quality or accepting unreasonable risk to infrastructure or safety. Our comparatively low rates reflect that this focus is not new, it has long been part of our culture. We continually work to keep our business efficient through digitization and automation and by engaging our employees on better ways to operate.

We manage our operations based on continuous improvement principles. While annual O&M expenses are dependent upon many factors, including specific work plans and emergent work performed in a particular year, our focus on managing O&M is relentless. The year-over-year operating cost comparisons in Company witness Lucas' testimony illustrate our commitment to and success with operating cost control.

We manage costs by closely monitoring I&M's major functional expenses through the annual budget process discussed by Company witness Lucas. We also use monthly reports to review and manage our expenditures. Cost control and process improvement are expected from each of our managers and are a metric for evaluating job performance. Once the annual budget is approved by management, the individual managers in charge of each department, operating district, power plant, or other functional area, are responsible and accountable for operating within the approved amounts.

Q. Are there costs of providing service that are not within the Company's control?

A. Yes. While we work to manage all costs, certain aspects of our cost of providing service are not solely within our control. The Company must comply with environmental and other regulations (including cyber and physical security of assets) and meet the ongoing needs of our customers for reliable and modern services. Fuel and other commodity costs, such as consumables and allowances, are driven by unit dispatch and market conditions, and are key examples of costs that are not solely within our control. As noted above, and discussed by Company witnesses Ali, PJM costs are another important example of costs that are not solely within the Company's control.

Q. Are the costs reflected in I&M's filing and the proposed rates reasonable and necessary to allow I&M to provide service to its customers?

A. Yes. A fundamental principle of rate regulation is that rates and charges accurately reflect the cost of providing service. The costs reflected in the proposed rates are reasonably representative of the Test Year cost of service and are reasonable and necessary for the Company to provide safe, adequate and reliable service during the time the rates are expected to be in effect.

As we work to meet our customers' energy needs, it is critical that the Company's financial health and integrity be maintained. To achieve this, we ask the Commission to approve the proposed package of rates and rate adjustment mechanisms so as to allow I&M an opportunity to earn an authorized rate of return that recognizes I&M's operating characteristics and to recover capital and operating expenses in a timely manner.

Q. Let's turn to a few specific expense items included in the cost of service. Please discuss further why it is reasonable and necessary to update the Cook Plant nuclear decommissioning expense.

A. As we move closer to the retirement of the Cook Plant, it is appropriate to update the nuclear decommissioning expense so as to match these costs, to the extent practicable, to the period the units are in service. It is a basic principle of utility regulation that costs of assets should be recovered during the period of time those assets are expected to be used by the utility to provide electric service. This means that all the funds needed for the decommissioning of the Cook Plant should be recovered through rates by the time the Cook Units are retired. As stated by Company witness Lies, Cook Unit 1 continues to be licensed to operate until 2034, and Unit 2 until 2037. As we move closer to the end of these license lives it is important to update the nuclear decommissioning expense to provide greater assurance of the availability of sufficient funds for the decommissioning of the Cook Plant at the end of its useful life.

To provide assurance that this objective is met through the rates charged during the service life of the Cook Plant, the Company proposes to increase the annual decommissioning expense to $5 million for each Cook Unit, for a total annual amount of $10 million, to target a 90% probability of having sufficient funds. The 90% probability is a reasonable step toward the goal of reflecting in rates a nuclear decommissioning that has a 100% funding probability, as we continue to move toward the end of the license lives.

This proposal is based on the analysis presented by Company witness Hill and the updated nuclear decommissioning cost study presented by Company witness Knight. As discussed by Company witness Hill, funds included in the revenue requirement for nuclear decommissioning are deposited in an external nuclear decommissioning trust fund in compliance with State and Nuclear Regulatory Commission (NRC) requirements.

Q. Please discuss why it is reasonable and necessary to update the Rockport Plant depreciation expense.

A. Similar to the reasoning for adjusting nuclear decommissioning expense, it is appropriate to update the Rockport Plant depreciation expense so as to match these costs, to the extent practicable, to the period the units are in service. In Cause No. 44967, I explained that the Rockport Unit 2 Lease expires in December, 2022 and I&M did not then believe that extending the term of the Lease was advisable. I also advised the Commission that the date through which Rockport Unit 1 can be expected to be in operation with any reasonable degree of certainty is December 2028. While we continue to assess options regarding the Lease, the Company's expected end of service life of Rockport Unit 1 continues to be December 2028 and the Company is assuming in our current IRP process that the lease of Rockport Unit 2 will not be extended.

The Settlement Agreement approved in Cause No. 44967 provided for the depreciation of Rockport Unit 1 through 2028 and the depreciation of the Rockport Unit 2 Dry Sorbent Injection (DSI) through 2025. The Settlement Agreement further provided that if the Unit 2 lease is not renewed, any remaining net plant associated with the Rockport Unit 2 DSI will be recovered through the Unit 1 depreciation and all remaining Rockport Unit 2 plant will be depreciated through 2022. The Company's proposed depreciation rates are consistent with these previously established service lives for the Rockport units and have been updated to reflect remaining investment, including the Rockport Unit 2 selective catalytic reduction (SCR) system, which the Company proposes to depreciate over the expected remaining life of Unit 1 (2028). The updated depreciation study and proposed depreciation rates are supported by Company witness Cash.

Q. Please explain why it is reasonable and necessary to incur PJM capacity performance insurance expense in the cost of service.

A. PJM's capacity performance rules monitor the reliability of a PJM member's capacity resources to ensure these resources are available to serve customer energy requirements. The rules, which include Non-Performance Charges in the event a generator does not meet PJM's capacity performance requirements, apply to I&M beginning June 1, 2019 and during a PJM Emergency or Performance Assessment Interval (PAI). If any of I&M's resources are experiencing an unexpected forced outage and are not available during a PAI, I&M will incur a Non-Performance Charge.

Because a generating unit can trip out of service unexpectedly due to factors beyond the Company's reasonable control, it is reasonable to take steps to mitigate exposure to the Non-Performance Charge. I&M, like many other generator owners in PJM, has acquired Capacity Performance Insurance as an ordinary and reasonable expense to offset the risk of generator non-performance. This cost is included in O&M Expense Adjustment No. 6 presented by Company witness Williamson. Given I&M's fleet operating history, Capacity Performance Insurance, which is procured before each PJM Delivery Year, currently costs about $1.00/MW-day with a reasonable deductible and policy loss limit.

It is appropriate to include this reasonable and necessary cost of providing service as a member of PJM in the PJM Rider. I&M operates four, large central station generating units, as shown in Figure TLT-1, comprising about 4500 MW, and the loss of one unit at the wrong time could result of Non Performance Charges of tens of millions of dollars. Given the annual cost of insurance of approximately $1.5 million is a fraction of the cost of a Non-Performance Charge for a large unit, and multiple PAIs can be assessed in a given year (multiple events/year), I&M insures this risk to protect our customers and the Company. Therefore, this reasonable and necessary cost of being a member in PJM should be recovered through the PJM Rider, which is the ratemaking mechanism used to recover other PJM costs.

Q. Do I&M's customers benefit from I&M being able to secure capital at a relatively low cost?

A. Yes. Maintaining access to the capital markets for competitive low cost debt and equity financing continues to be paramount for I&M and its customers. I&M's ability to secure access to low cost capital to fund its operations is heavily dependent on regulatory support that authorizes rate increases in a timely manner, manages known risks, provides predictability and fairly compensates equity investors. Being in good financial health and having predictable revenues benefit customers by allowing I&M to compete both internally and externally for access to capital at reasonable terms relative to others in the utility industry.

VIII. IMPACT ON CUSTOMERS

Q. Is the Company mindful of the impact of rate increases on customers?

A. Yes. We consider our ongoing investments through a lens of providing safe and reliable electric service while always being mindful of the cost impacts. As stated above, we are proud of our heritage as a low-cost provider and remain committed to effectively managing our business. We also recognize the importance of structuring rates to reflect the cost of service. Under this approach, the way a customer uses the system is accurately and fairly reflected in the customer's rates. This enables customers to reasonably evaluate options and make rational decisions. Company witnesses Duncan and Nollenberger further address the customer impact through the Company's three-step phase-in rate adjustment mechanism.

Q. How does the Company's proposal to update its residential rate design further those objectives?

A. Company witness Nollenberger presents the Company's proposed rate design for residential service. The Company proposes to increase the residential monthly service charge from $10.50 to $15.00. We also propose to address the remaining fixed costs that are not reflected in the service charge through a declining block volumetric kWh charge structure.

Importantly, it should be recognized that the percentage increase in the service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, "gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill."[11]

While proposals to change the residential rate design have been controversial in past cases, it is critical that we continue to make progress on

[11] 44576 Order at 72.

properly designing our rates to avoid inappropriately shifting costs among customers, as I discussed above. As the Commission has previously recognized:

> **Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided.**[12]

If I&M's rates are not properly designed, some customers will be incented to avoid fixed costs buried in the variable charge, leaving those fixed costs to be spread among the other customers.

Under I&M's proposed rate design, the total bill for all customers will better reflect the underlying cost of service. Additionally, the proposed rate design provides benefits for those low income customers most dependent on electricity, while remaining fair to low income low usage customers and retaining significant opportunity for energy efficiency.

Q. Does the Company offer assistance to customers who may need help paying their bill?

A. Yes. We recognize that it is difficult for some customers to pay their electric bills, and we continue to offer payment assistance programs ranging from agreements to extend a bill payment a few days to longer monthly payment programs. The Company also offers a level payment program that helps a customer stabilize the monthly bill so it will be more predictable and allow customers to better manage their resources. I&M also works with many private and non-profit community-

[12] 44576 Order at 72.

based local and federal organizations that provide assistance to low-income residents.[13]

In addition, I&M offers energy efficiency programs to help customers reduce their energy usage. When the Indiana General Assembly enacted the energy efficiency plan statute, it specifically provided that such plans may include an energy efficiency assistance program for income qualified customers whether or not the program is cost effective.[14] The Company had already been offering this type of program and we remain committed to working with low income customers to utilize these programs to make their homes more efficient.

The deployment of AMI will give our customers better insight into their energy usage. This in turn will allow informed decisions and opportunities for customers to reduce their electric bill by changing their use of electricity.

Finally, the Company proposes to continue many of the collaborative pilot programs established pursuant to the Settlement Agreement approved in Cause No. 44967 (Energy Share Pilot Program, Low Income Weatherization, and Neighbor to Neighbor Pilot Program) and establish a new Income Qualified Health & Safety Pilot Program to address health and safety needs of customers to enable better use of other critical customer assistance programs. Company witness Lucas addresses these programs.

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[13] Additionally, our state and federal legislatures provide numerous public assistance programs, including housing, food, health care, education, and utility bill assistance programs, including programs for our customers who heat with gas (provided by other companies) as well as our customers who heat with electricity. Any assessment of electric bill impact on low income customers is incomplete if viewed in isolation from other public assistance benefits available to these customers.

[14] Ind. Code § 8-1-8.5-10(h).

IX. NEW SERVICE OPTIONS

Q. Is the Company proposing any new service offerings for residential customers?

A. Yes, the new residential service offerings include a new residential demand metered service pilot (Tariff R.S.D.). This pilot will provide customers an additional service option that may fit their usage profile and will allow the Company to gain experience with a residential tariff with demand components. As discussed by Company witness Cooper, this optional pilot will be limited to 4,000 customers, which is approximately one percent (1%) of the Company's total Indiana residential customer base.

The Company also seeks to support the electrification of transportation because doing so is beneficial to our customers. The transportation sector is a large consumer of energy in the U.S. and yet the vast majority of energy consumed in transportation today comes from petroleum.[15] In addition to improving our electric utility load and load shape, transportation electrification has the potential to provide grid support, distributed storage and demand response. Electrifying the transportation sector supports economic development, aids state and national security, and improves the environment. Because plug-in electric vehicles (PEVs) must be charged, utility infrastructure investment and associated rate design is key to both the ongoing development of this market and to managing the shape of this load so that it does not adversely affect utility systems, but instead benefits our customers.

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[15] Edison Electric Institute *Transportation Electrification*, June 2014, p. 1 citing U.S. Energy Information Administration (EIA).

As Company witness Lehman explains, the Company's comprehensive program, "IM Plugged In", is designed to support the expansion of PEV at scale by aligning customer incentives for off-peak charging to simultaneously provide benefits to PEV drivers and all I&M customers. Company witness Cooper explains the Company's proposal to expand its service offering for residential customers who need to charge PEVs. This tariff will provide eligible customers an opportunity to lower the cost of charging their PEV by installing a submeter and charging their PEV during off-peak hours.

Finally, as discussed by Company witness Lucas, the Company is proposing to consolidate its Green Power Rider (GPR) and Renewable Energy Option (REO) offerings into a single revised voluntary renewable program called IM Green that will offer customers the ability to purchase renewable energy through a combination of wind and solar Renewable Energy Certificates (RECs). Company witness Cooper presents the proposed tariff which includes a custom contract option for large customers.

X. CONCLUSION

Q. Please summarize your testimony and recommendations.

A. As mentioned above, the electric business continues to change as a result of environmental regulation, economic conditions, evolving technology change and changes in the way our customers use electricity and want to be served. I&M has done a great deal to be efficient on its operations and we are mindful of the need to continue to control our costs and increase productivity. Our goal is to invest wisely, operate our business efficiently, and provide a customer experience that serves customers the way they want to be served.

While the Company has made significant progress, as we move into the future, we must continue to work hard every day to demonstrate the value of our service to our customers. We must continue our efforts to rectify our rate design and expand our service offerings so that customers will rationally choose I&M as their energy service provider and Indiana as a place to live and work. The Company remains committed to providing new options to our customers through voluntary programs and improved access to renewable energy.

Our current rates are not sufficient to cover the Test Year cost of providing service and it is our responsibility to seek rate relief to support our ongoing effort to address aging infrastructure, secure long-term reliability and resiliency, enhance the service we provide through new technology and automation, and otherwise meet the ongoing energy and capacity needs of our customers. The proposals we make in this case allow us to continue to embrace technology advancements and use them to support economic development and innovation for the benefit of customers, both in the short-term and while the future unfolds.

We ask the Commission to approve a revenue requirement and design rates based on sound cost of service and ratemaking principles. We also ask the Commission to find that I&M's proposal is a balanced, reasoned and rational solution to the Company's need for both cost recovery and a reasonable opportunity to earn a reasonable return, while we continue to fulfill I&M's duty to provide reliable electric service and facilities to our customers.

Q. Does this conclude your pre-filed verified direct testimony?

A. Yes, it does.

VERIFICATION

I, Toby L. Thomas, President and Chief Operating Officer of Indiana Michigan Power, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 5-13-2019

Toby L. Thomas

Toby L. Thomas

Indiana Michigan Power Company
2019 Rate Case
Index of Issues, Requests, and Supporting Witnesses[1]

Subject	GENERAL	Supporting I&M Witness
Test Year	Twelve Months Ended December 31, 2020.	• Williamson.
Historical Base Period	Twelve Months Ended December 31, 2018.	• Williamson.

REVENUE REQUIREMENT		
Subject	I&M Request	Supporting I&M Witness
Overall Revenue Increase	• Total annual increase in revenue of approximately $172 million, or 11.75% to be phased in over three steps. • Phase-In Rate Adjustment (PRA): o Phase I: $82.5 million or 5.63%. o Phase II: $129 million or 8.81%. o Phase III: $172 million or 11.75%.	• Thomas (overview). • I&M Financial Exhibit (details). • Williamson (policy). • (See "Cost of Service and Rate Design" below for description of PRA; see also Ross (general regulatory accounting and various adjustments).)
Advanced Metering Infrastructure (AMI)	• Preapproval under IC 8-1-2-23 of three-year plan (2020-22) to rollout AMI in I&M's Indiana service territory. • Timely recovery of AMI deployment costs through new AMI Rider. • Cost-based AMI opt-out tariff. • Standard retirement accounting for AMR meters currently installed in Indiana service territory.	• Thomas (overview). • Isaacson (deployment, operational benefits). • Lucas (technology, customer engagement and programs). • Williamson (regulatory treatment). • Cooper (AMI opt-out). • Cash (AMR retirement).
Depreciation	• Set new depreciation rates and reflect the resulting depreciation expense in base rates based on depreciation study. • Adjust Rockport Unit 2 selective catalytic reduction (SCR) depreciation rate to align with expected end of life of Rockport Unit 1 in 2028.	• Cash (depreciation). • Thomas (SCR overview).

[1] This Index of the Company's case-in-chief is intended to highlight issues and is not an exhaustive list of I&M's requests in this proceeding. A complete account of I&M's requested relief can be found in I&M's case-in-chief, including but not limited to I&M's petition, testimony, exhibits, workpapers, and MSFR responses. The I&M Financial Exhibit provides an additional index.

REVENUE REQUIREMENT		
Subject	**I&M Request**	**Supporting I&M Witness**
Distribution	• Reflect forecasted distribution O&M and capital in rates, including programs and projects in I&M's 2019-20 Indiana Distribution Plan: o Continue vegetation management program approved in Cause No. 44967 (hereinafter 44967). o Asset renewal and reliability program. o Customer service, city and state requirements and other. o Major projects. o Risk mitigation program. o Grid modernization program (including AMI). • Continue deferral accounting authority for major storm restoration cost reserve as in 44967.	• Isaacson (distribution O&M and capital). • Williamson (major storm reserve accounting).
Economic Development Programs	• Continue the third component of the Economic Impact Grant (EIG) Program established in 44967 which establishes annual funding for grants ($137.5k/year reflected in rates). • Continue economic development rider as clarified with no termination date. • Approval of new pilot programs – (a) Apprenticeship and Training pilot ($350k/year for two years) and (b) Building Development pilot ($150k/year for two years).	• Lucas (programs) • Cooper (associated tariff changes).
Electric Transportation (IM Plugged In Pilot Program)	• Approval of residential plug-in electric vehicle (PEV) incentives, including overnight charging rate and $500/port incentive for charging equipment (2-year pilot; annual cap of 1,000 customers, 1,000 ports, $500k). • Approval of multiunit dwelling PEV incentive of $250/port or CIAC reduction (2-year pilot; annual cap of 100 customers, 400 ports, $100k). • Approval of fleet and workplace charging PEV incentive of $250/port (2-year pilot; annual cap of 100 customers, 400 ports, $100k). • Deferral of program costs.	• Lehman (program). • Cooper (associated tariff changes). • Williamson (deferral).

REVENUE REQUIREMENT		
Subject	I&M Request	Supporting I&M Witness
Financial Forecast	• Set rates based on I&M's Test Year financial forecast. • Reflect forecasted O&M and capital investments in rates based on I&M's work plans.	• Lucas (overall development of O&M and capital forecast). • Heimberger (forecasting model). • Lies (nuclear O&M and capital). • Kerns (non-nuclear generation O&M and capital). • Isaacson (distribution O&M and capital). • Ali (PJM costs). • Burnett (load forecast).
Generation (Fossil, Hydro, and Solar))	• Reflect forecasted generation O&M in rates. • Reflect forecasted generation capital investment in rates, including: o Rockport Unit 2 SCR (CPCN granted in Cause No. 44871). o Coal Combustion Rule (CCR) compliance. o Enhanced DSI (adjustment for capital expense and O&M (consumables)). • Adjust Test Year consumables expense to reflect ongoing level; embed Test Year consumables and allowances expense in base rates and track over/under expense through environmental cost rider (ECR).	• Kerns (generation O&M and capital investment, variability of consumables and allowances expense). • Thomas (consent decree modification for Enhanced DSI). • Williamson (adjustments for Enhanced DSI capital and O&M, tracking consumables and allowances).
Nuclear Decommissioning and Spent Nuclear Fuel Trust	• Increase Indiana retail annual contribution to Nuclear Decommissioning Trust (NDT) to $10M to target 90% probability of have sufficient funds. • Continue current $0 funding level for Spent Nuclear Fuel Trust (SNFT) and adjust permissible trust investments for the assets that exceed the Indiana jurisdictional liability by 1.05 so that they align with the guidelines for the Decommissioning Trust.	• Thomas (overview) • Hill (NDT likelihood of success, SNFT investments). • Knight (nuclear decommissioning cost study). • Lies (nuclear decommissioning overview).

REVENUE REQUIREMENT		
Subject	I&M Request	Supporting I&M Witness
Nuclear Operations	• Reflect forecasted nuclear O&M in rates. Reflect forecasted nuclear capital investment in rates, including in-service Life Cycle Management (LCM) projects and other investments. • Continue the deferral of dry cask storage costs not reimbursed by the DOE as in 44967. • Amortize and reflect in rates costs of compliance with Clean Air Act Section 316b rules ("316b").	• Lies (nuclear O&M and capital investment, description of dry cask storage and 316b). • Williamson (LCM Rider, dry cask storage deferral, regulatory treatment of 316b).
Ongoing and New Customer Assistance Programs	• Continue following programs established in 44967: o Energy Share Program with $250k annual funding reflected in rates. o Low Income Weatherization Program with $50k annual funding reflected in rates. o Neighbor to Neighbor Program with $50k annual funding reflected in rates. • Low Income Arrearage Forgiveness Pilot Program as agreed in 44967. • Establish new Income Qualified Safety & Health Pilot Program to address safety and health issues that prevent energy audits with $100k annual funding reflected in rates.	• Lucas.
Prepaid Pension Asset	• Continue to reflect in rate base.	• Hill (description of pre-paid pension). • Williamson (regulatory treatment).
Return on Equity (ROE)	• Authorize 10.5% ROE.	• Hevert.
Taxes	• Reflect forecasted Test Year tax expense in base rates. • Apply gross revenue conversion factor (GRCF). • Over/under deferral for excess normalized accumulated deferred federal income taxes (ADFIT) once non-normalized excess ADFIT are fully amortized pursuant to settlement in 44967. • Reflect non-normalized excess ADFIT unamortized balance in rate base to account for jurisdictional differences in amortization rate.	• Kelly (tax expense, ADFIT, GRCF). • Williamson (ADFIT deferral, non-normalized excess ADFIT unamortized balance in rate base).

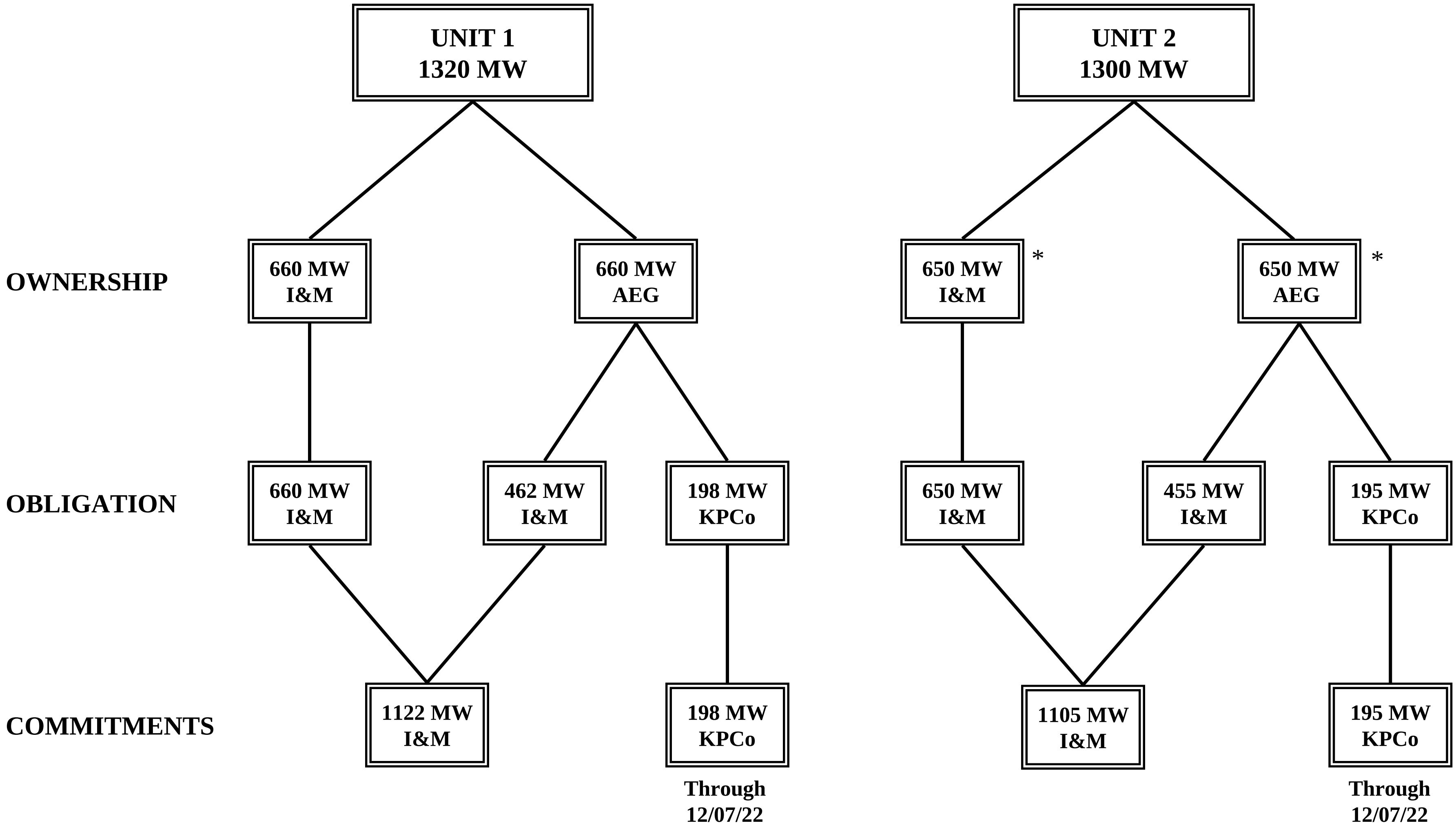
REVENUE REQUIREMENT		
Subject	**I&M Request**	**Supporting I&M Witness**
Weighted Average Cost of Capital (WACC)	• Authorize forecasted WACC applied to original cost rate base.	• Messner (overall WACC calculation, financing activity). • Heimberger (equity balance). • Kelly (ADFIT balance). • Hevert (ROE).
Wholesale Contract Expiration	• Annualize effect of expiration of wholesale contracts on May 31, 2020. • Credit PRA to reflect IMMDA contracts through May 31, 2020).	• Thomas & Williamson (overview). • Nollenberger (annualization adjustment). • Duncan (rate credit component of PRA).

COST OF SERVICE AND RATE DESIGN		
Subject	**I&M Proposal**	**Supporting I&M Witness**
Class Cost of Service Study (CCOSS)	• Use of same allocation methodology as proposed by I&M in 44967.	• High (CCOSS, allocation factors).
Jurisdictional Cost of Service Study (JCOSS)	• Use of same study approach as in 44967. • New demand and energy allocation factors “Excluding Shopping” to reflect customer choice in Michigan service territory.	• Duncan.
Overall Rate Design	• Allocation of revenue increase to eliminate 25% of current subsidies. • Better alignment of residential fixed costs with rate design through approval of: o $15 monthly service charge. o Declining block rate proposal. • New optional residential demand tariff (Tariff RSD).	• Nollenberger (rate design). • Cooper (Tariff RSD).
Phase-In Rate Adjustment (PRA)	• Phase-in rate adjustment (PRA) credit for rate base additions during Test Year as in 44967. • I&M to certify actual Test-Year-end rate base pursuant to same procedure as in 44967. • Additional phase-in credit for revenue associated with IMMDA contracts ending May 31, 2020.	• Duncan (description of PRA, calculation of credits). • High (Phase-In COSS). • Nollenberger (PRA rate design).

COST OF SERVICE AND RATE DESIGN		
Subject	I&M Proposal	Supporting I&M Witness
IM Green Renewable Energy Rider	• Consolidate existing Green Power Rider and Renewable Energy Option into single *IM Green* tariff voluntary offering that will offer customers the ability to purchase Renewable Energy Certificates (RECs) as a percentage of usage at an indexed market rate. • Option for large customers to enter into custom contracts under *IM Green* program.	• Lucas (support for program). • Cooper (tariff changes).
Other Rider Proposals	• DSM/EE Rider – Remove costs/revenues from Test Year forecast and continue to track costs, including cost of DSM/EE plan for 2020 and beyond to be addressed in separate docket. Adjust rider to reset net lost revenues and to reflect additional DSM/EE-related capital included in base rates. • Environmental Cost Rider (ECR) –Track over/under Test Year level of consumables and allowances embedded in base rates; continue tracker recover of Rockport Unit 2 SCR costs until reflected in base rates. • FAC – Reset level of costs embedded in base rates (base cost of fuel or basing point) based on Test Year forecast, continue waiver of purchased power benchmark on ongoing basis and continue crediting customers for participation in voluntary renewable programs. • LCM Rider – Continue as in 44967 but with Test Year end in-service LCM capital investments reflected in base rates via PRA. • OSS/PJM Rider – o Continue to track off-system sales margins (OSS) in OSS/PJM Rider with 95%/5% Customer/Company sharing with no margins embedded in base rates as in 44967. o Continue to track all PJM NITS costs in OSS/PJM Rider with no PJM NITS costs embedded in base rates as in 44967; eliminate cap and sunset. o Embed new Test Year level of PJM non-NITS costs in rates and continue to track over/under embedded level in OSS/PJM Rider as in 44967. o Embed capacity performance insurance costs resulting from PJM Fixed Resource Requirement in base rates and track over/under embedded level in OSS/PJM Rider. • Resource Adequacy Rider (RAR) – Continue as in 44967 with new Test Year level of non-FAC purchased power costs embedded in base rates; eliminate cap and sunset.	• Williamson (changes to riders and ongoing waiver of purchased power benchmark). • Heimberger (FAC basing point). • Thomas (capacity performance insurance).

COST OF SERVICE AND RATE DESIGN		
Subject	I&M Proposal	Supporting I&M Witness
Terms and Conditions of Service and Tariffs	• New miscellaneous service charges and meter tampering fee. • New data privacy policy. • Treat EZ Bill program costs and revenues as above the line like other I&M tariff offerings (no costs or revenues reflected in rates in this proceeding).	• Cooper (service charges, privacy policy). • Williamson (EZ Bill accounting).
Transmission Costs	• Embedded Test Year level of non-NITS PJM costs in base rates. • Track all NITS costs in OSS/PJM Rider with no cap or sunset.	• Williamson (PJM Rider). • Ali (transmission investment, PJM cost forecast).

ROCKPORT PLANT
OWNERSHIP, OBLIGATION AND COMMITMENTS



* Both I&M and AEG sell and leaseback their respective shares of Rockport Unit 2. The lessors are non-affiliated, non-utility institutions. During the term of the lease, I&M and AEG each has full entitlement to 50% of the power and energy from Rockport Unit 2.

The Edison Foundation
INSTITUTE for
ELECTRIC INNOVATION

Report

Electric Company Smart Meter Deployments: Foundation for a Smart Grid

December 2017

Prepared by:
Adam Cooper

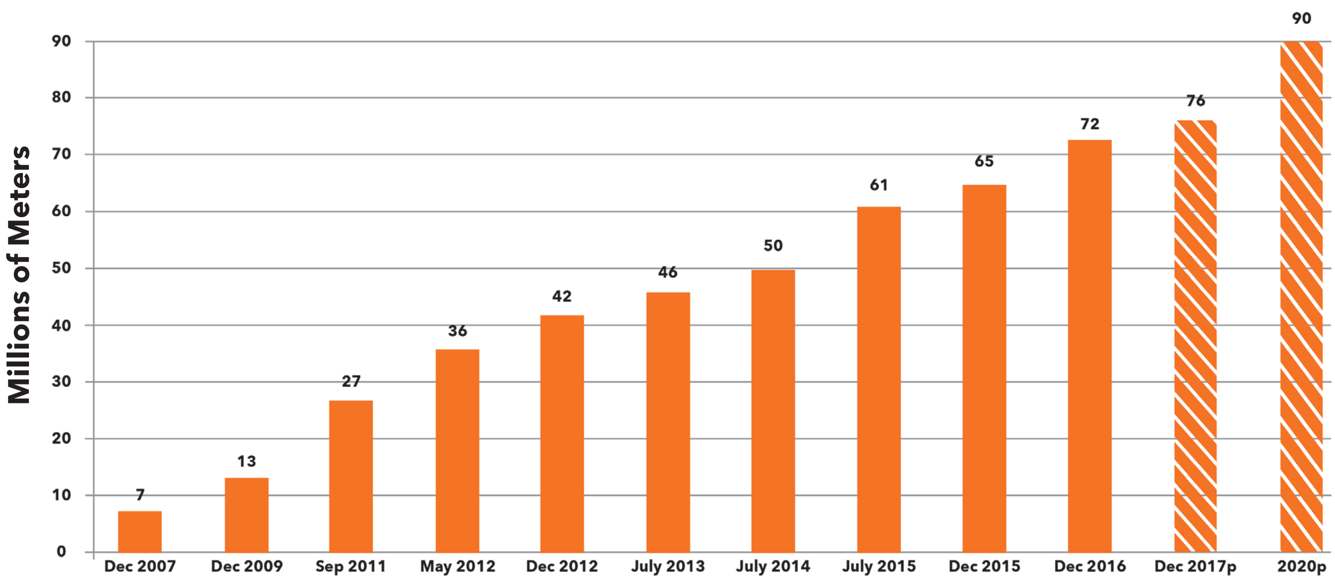
EXECUTIVE SUMMARY

The transition of the electric power system is underway, and a key technology creating big changes for customers and electric companies continues to be smart meters.[1] While deployment of smart meters began a decade ago, electric companies continue to find ways to create value from the data and capabilities smart meters enable. Investing in the distribution grid, particularly in smart meters, is the foundation for a customer-facing, modern energy grid.

In this report, we discuss some of the innovations, benefits, and capabilities enabled by smart meters; summarize the results of the Institute for Electric Innovation's (IEI's) 2017 Smart Meter Survey; and, provide our perspective on the growing importance of investing in the distribution grid.

As shown in Figure 1, smart meter installations have grown dramatically since 2007. As of year-end 2016, electric companies had installed 72 million smart meters, covering more than 55 percent of U.S. households. Based on survey results and approved plans, estimated deployments are expected to reach 76 million smart meters by the end of 2017 (covering 60 percent of U.S. households) and 90 million by 2020.

Figure 1: U.S. Smart Meter Installations Approach 76 Million; Projected to Reach 90 Million by 2020



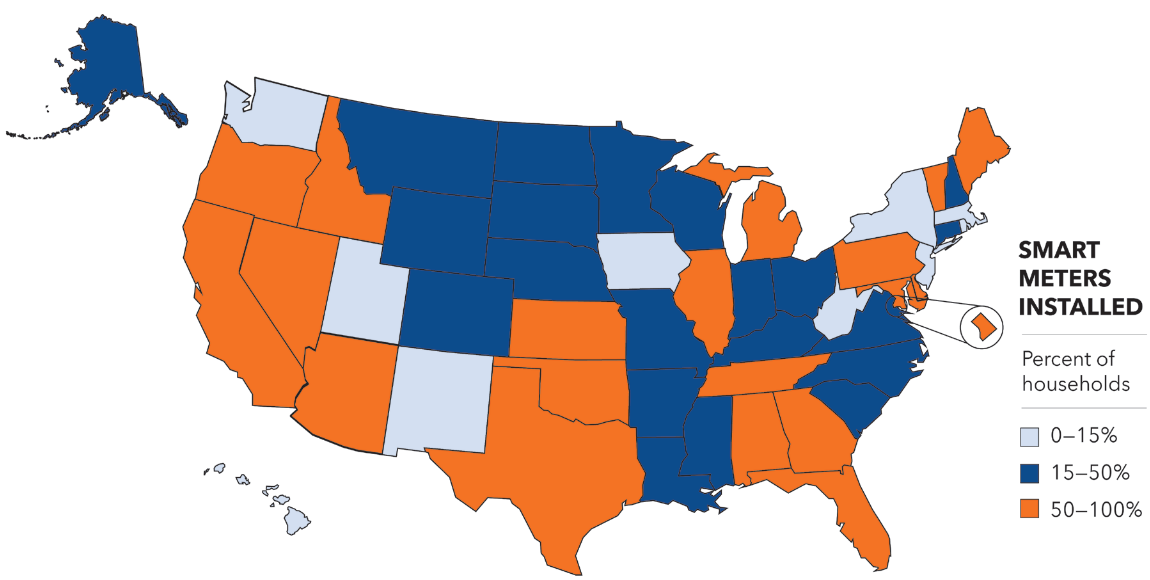
1. Smart Meters, or Advanced Metering Infrastructure (AMI), are digital meters that measure and record electricity usage data hourly, or more frequently, and allow for two-way communication between electric companies and their customers.

HIGHLIGHTS

- Electric companies had installed 72 million smart meters, covering more than 55 percent of U.S. households, as of year-end 2016.
- Deployments are estimated to reach 76 million smart meters by the end of 2017 and 90 million by 2020.
- More than 40 electric companies in the United States have fully deployed smart meters.[2]
- Electric companies are using smart meter data today to enhance grid resiliency and operations, integrate distributed energy resources (DERs), and provide customer solutions.
- Smart meters provide a digital link between electric companies and their customers and open the door to new and expanded services, such as time-based pricing, load control, budget billing, high-usage alerts, push notifications, and web services for energy management.
- Smart meters enable two-way power and information flows to improve visibility into the energy grid.
- Electric companies are focused on modernizing the energy grid and are projected to invest more than $35 billion in the distribution system in 2017.
- A digital energy grid is essential to integrate DERs seamlessly, enhance reliability, reinforce resiliency, and provide more solutions to customers.

Electric companies across the U.S. are leveraging smart meter data to better monitor the health of the energy grid, more quickly restore electric service when outages occur, integrate DERs, and deliver energy solutions to customers. Figure 2 shows smart meter deployments by state.

Figure 2. Smart Meter Deployments by State, 2016 (% of households)



2. An in-depth list of smart meter deployments by electric company is at the end of this report.

INTRODUCTION

This report describes how electric companies are using smart meter data today to enhance grid resiliency and operations, integrate DERs, and provide customer solutions, and discusses the growing importance of the energy distribution grid.

Given the impact of the 2017 hurricane season on the electric power system in some areas of the country, this report provides recent examples of how electric companies used smart meters to enhance grid reliability and operations.

ENHANCING GRID RELIABILITY AND OPERATIONS

Having a reliable supply of electricity is more than just a convenience; it's a necessity. Our economy — and our way of life — depend on it. Smart meters are changing the ways electric companies respond to problems on the energy grid, and the results speak for themselves.

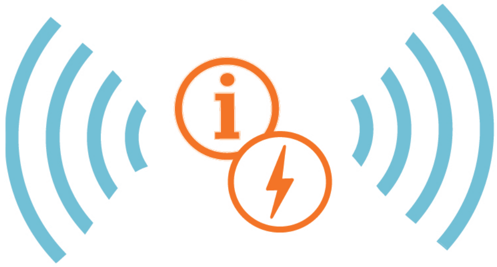
During the historic 2017 hurricane season, smart meters were instrumental in the speedy recovery efforts following Hurricanes Harvey and Irma in August and September. The data from smart meters, when integrated with other systems, gave electric companies "visibility" into the distribution grid and the ability to better coordinate storm response efforts and communication with customers.

CenterPoint Energy has been investing in smarter energy infrastructure since 2009. The company has deployed smart meters to virtually all 2.4 million customers in the Houston area; automated 31 substations, installed 872 Intelligent Grid Switching Devices on more than 200 circuits; and built a private wireless radio telecommunications network across a 5,000-square mile footprint. In 2012, CenterPoint created an asset management analysis and strategy unit, which coordinates business intelligence and data analytics activities across the entire company, enabling the information generated by these technologies to be used more efficiently.

At CenterPoint, smart meters and data analytics provide situational awareness so that crews can be sent to the highest priority outage locations automatically. On circuits that have switching devices or automation, faults are isolated and a large percentage of customers can be restored within minutes.

During Hurricane Harvey, CenterPoint operated more than 250 intelligent grid switching devices covering more than 140,000 customers. The company also flew 15 drones over more than 500 locations to assess damage, efficiently direct crews to accessible locations, and identify equipment needing further inspection. Real-time analytics were used to correlate weather and flood information with outages and to provide operations crews with critical situational awareness and decision-making tools. These steps helped CenterPoint avoid almost 41 million outage minutes during Hurricane Harvey.

Smart meters enable two-way power and information flows to



improve visibility into the health of the energy grid

Florida Power & Light Company (FPL) has invested heavily in energy grid modernization—physical grid hardening, digital grid technologies, and data analytics—to enhance grid resiliency and to improve its understanding of the nature and extent of outages, improving its ability to restore power when outages do occur.

To date, FPL has installed 4.9 million smart meters that let the company know when individual customers are out of power and has deployed more than 83,000 intelligent grid devices and smart switches. As a result, the electric company has deep visibility into its distribution grid. This greatly improves FPL's understanding of the nature and extent of outages when they do occur, improves communications with customers, and improves outage restoration times.

In 2017, Hurricane Irma impacted more than 4.4 million of FPL's nearly 5 million customers. It was the largest outage in FPL's history, and was the first time that a storm impacted all 27,000 square miles of its service territory. System hardening helped to make the system more resilient, and investments in digital grid technologies and data analytics greatly improved FPL's understanding of the nature, extent, and locations of outages, allowing the company to restore hundreds of thousands of customers during the storm without the need to roll trucks. In fact, even before Irma exited FPL's service territory, approximately 1 million customers had been restored. And, for 2 million customers, power was restored by the end of the first full day of restoration work.

Smart meters played a key role in CenterPoint's and FPL's ability to respond rapidly to outages resulting from the two hurricanes.

The sensing capabilities in smart meters continue to advance, and electric companies now are collecting more complete power characteristics (e.g., voltages and reactive power) in addition to consumption and power on/off status from the meters.

By integrating voltage and reactive power data collected by smart meters with Distribution Management Systems (DMS), electric companies are implementing distribution automation and circuit reconfiguration, volt/VAR management, device monitoring, and predictive asset maintenance capabilities. For example, American Electric Power, Baltimore Gas & Electric, Dominion, DTE Energy, and several other electric companies are using voltage and power quality data collected and transmitted by smart meters for voltage optimization and proactive identification of distribution transformers that are at risk to fail.

And, as the energy grid integrates more distributed energy resources (DERs) and as switching and dynamic automation capabilities proliferate, having an accurate representation and mapping of transformers to customer meters is critical for public safety, faster outage restoration, and the integration of DERs.

The more basic functions of smart meters—such as cross-referencing smart meter data with billing systems to reduce uncollectable expenses, reduce consumption from inactive meters, and better detect energy theft, and reducing the need to "roll trucks" to a customer site to read a meter or troubleshoot—still continue to provide major benefits on a daily basis.

"The data generated by smart meters provides the basic information for integrating distributed energy resources and modeling their behavior."

BEYOND INTEGRATING DISTRIBUTED ENERGY RESOURCES

As DERs, such as private or rooftop solar PV, energy storage systems, electric vehicles, and connected home devices like smart thermostats and smart appliances, continue to grow, electric companies need greater visibility into the performance of these systems to better utilize these resources for efficient distribution grid operations. The data generated by smart meters provides the basic information for integrating these DERs and modeling their behavior.

Going forward, the computing power in each smart meter opens the door to applications beyond traditional metering services.

- For example, applications are under development to predict the behavior of customer-sited energy resources so that these resources can be utilized more efficiently.
- Another example is using smart meters as platforms for distributed analytics, decision making, and communication across devices on the grid edge.

PROVIDING CUSTOMER SOLUTIONS

Smart meters provide a digital link between electric companies and their customers and open the door to new or expanded customer solutions.

Smart Pricing Options

Residential customers have proven time and again that they are engaged, willing to participate in pricing programs, and satisfied when they do participate.

- Smart pricing programs are growing across the United States. Today, millions of customers with smart meters are enrolled in time-based pricing programs that reward participants for reducing energy consumption voluntarily during designated peak times when demand for electricity is expected to be especially high.
- While the majority of customers enrolled in smart pricing programs are responding to time-of-day, or peak pricing signals today, smart meters also support residential rates with demand charges. Demand information can be utilized by customers to better inform their usage decisions.
- Demand response programs are benefitting from the deployment of smart meters and two-way communication, enabling electric companies to communicate with customers to get accurate feedback on demand reductions.
- Smart meters also help customers to leverage smart charging for plug-in electric vehicles to better manage vehicle charging in response to price signals.

Smart meters provide customers control

& flexibility over their energy use

Other Services

Electric companies are providing a range of other services to customers with smart meters, including:

- Power alerts that notify customers if their power is out, provide an estimated time to restore service, and deliver a final notice when the power is back on.
- Remote connect and disconnect services that help customers who are moving receive faster and more convenient electric service.

- Budget setting options that allow customers to set spending goals and that provide weekly updates to show how they are performing against their goals.
- High usage alerts that notify customers if their bill is projected to be higher than normal.
- Fewer estimated bills for a better customer experience.
- Pre-payment and/or pay-as-you-go options.
- Online access to view and download energy use information.
- Decision support tools to assist customers in the evaluation of energy management options, solar or battery energy storage installations, and electric vehicle purchases.

Customers are benefiting from smart meters in many different ways. And, as electric companies continue to engage with customers via online platforms and apps, more customer services and solutions will be powered by smart meter data.

GROWING IMPORTANCE OF DISTRIBUTION GRID

Electric company investments in the distribution grid are projected to be more than $35 billion in 2017. Through targeted investments, electric companies are developing a digital distribution grid that can serve as a platform to enhance grid resiliency and reliability, integrate a growing number of DERs, and provide more customer solutions.

Investing in smart meters is one of the first steps in moving toward a digital distribution grid and recent approvals of smart meter deployments in Indiana, Louisiana, New York, North Carolina, and Ohio demonstrate their continued importance as a critical technology to support the energy grid of the future.

Distribution grid digitization is not a one-off technology project, it is an iterative process. A distribution grid platform requires advanced grid operating systems, robust communications network, and intelligent grid devices. Increasingly, electric company distribution resource plans identify and prioritize grid modernization investments—both software and hardware—that must be made to improve visibility into the distribution system, integrate growing numbers of DERs, and provide a platform for new customer solutions. The role of the distribution grid continues to evolve, but smart meters remain the fundamental building block.

CONCLUSION

Building a solid, smart foundation for a more distributed, increasingly clean, and increasingly digital energy grid allows electric companies to deliver new services to customers. Investing in smart meters is one of the first steps in building a smarter energy infrastructure

As electric companies continue to manage, operate, and invest in an increasingly digital energy grid, the next step is to utilize the data being generated as a strategic asset to improve grid operations, use customer resources more efficiently, and offer new services to customers.

Table 1. Summary of Smart Meter Installations and Projected Deployments

Electric Company Type	Meters Installed (2016)	Estimated Meters Installed (2017)	Projected Meters Installed (2020)
Investor-Owned	53,350,000	57,000,000	70,000,000
Public Power Utilities and Electric Cooperatives	18,650,000	19,000,000	20,000,000
U.S. Total	**72,000,000**	**76,000,000**	**90,000,000**

Note: Totals are rounded.

Table 2. Smart Meter Installations and Projected Deployments by Investor-Owned Electric Company

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
Alliant Energy	IA WI	476,000	961,000	Alliant Energy Corporation is comprised of two subsidiaries, Wisconsin Power and Light (WPL) and Interstate Power and Light (IPL). The WPL smart meter implementation was completed in December of 2011, totaling 476,000 meters. In Fall of 2017, IPL began deployment of 485,000 smart meters in Iowa. Installations are taking place over a three-year period with anticipated commisioning/provisioning of the smart meters by end of 2019.	IEI Smart Meter Survey 2017
Ameren Illinois	IL	425,000	1,249,000	Ameren Illinois installed 425,000 smart meters through end of 2016 and anticipates 700,000 meters installed by end of 2017, and full deployment of 1,249,000 meters by December 2019.	IEI Smart Meter Survey 2017

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
American Electric Power	IN OH OK TX VA	1,910,000	2,965,000	AEP's Indiana Michigan Power subsidiary has deployed 10,600 meters to customers in South Bend, IN; AEP Ohio has deployed 136,000 in the Columbus area and will reach full deployment of over 1 million meters by 2020; AEP Texas reached full deployment of 1,200,000 meters; and AEP's Public Service Company of Oklahoma reached full deployment of 564,000 meters in 2016. Appalachian Power started a smart meter pilot in 2017.	IEI Smart Meter Survey 2017
Arizona Public Service	AZ	1,329,000	1,500,000	APS achieved full deployment of smart meters in May 2014. 2020 projection accounts for new customers in service territory.	IEI Smart Meter Survey 2017
Avista Utilities	WA	13,000	263,000	Avista has installed 13,000 smart meters in Pullman, WA, as part of a Smart Grid Demonstration Grant project. Avista is in the early planning stages of a full rollout of 263,000 meters in Washington.	IEI Smart Meter Survey 2017
Baltimore Gas & Electric	MD	1,244,000	1,270,000	BG&E installed 1,244,000 smart meters through December 2016 and is 98 percent deployed.	IEI Smart Meter Survey 2017
Black Hills Energy	CO MT SD WY	209,000	209,000	Black Hills Energy has fully installed 209,000 smart meters in its service territory across four states.	IEI Smart Meter Survey 2017
CenterPoint Energy	TX	2,388,000	2,388,000	CenterPoint Energy received approval in 2008 to install an advanced metering system across its service territory. It completed deployment in July 2012 and currently has 2,388,000 smart meters installed in the greater Houston area.	IEI Smart Meter Survey 2017; EIA Form 861

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
Central Maine Power	ME	630,600	630,600	Central Maine Power Company completed its smart meter deployment in 2012 and currently has 630,600 smart meters installed.	EIA Form 861
Cleco Power	LA	287,000	287,000	Cleco Power fully deployed smart meters across the company's entire service territory, after receiving approval from the Louisiana Public Service Commission in 2011.	IEI Smart Meter Survey 2017
Commonwealth Edison	IL	3,035,000	4,192,000	In June 2013, ComEd received regulatory approval for full deployment of smart meters. As of December 2016, approximately 3,035,000 smart meters were deployed. ComEd anticipates installations reaching 3,770,000 customers by end of 2017, with full installation complete to 4,192,000 customers in 2019, several years in advance of the originally scheduled 2021 completion date.	IEI Smart Meter Survey 2017
Consolidated Edison	NY	4,100	2,000,000	ConEdison received approval to deploy 3,600,000 smart meters between 2017 and 2022. Installations began on Staten Island in summer 2017, and 2 million meters are projected to be installed by 2020.	Case 15-E-0050, Company Website
Consumers Energy	MI	1,355,000	1,824,000	Consumers Energy deployed 1,355,000 smart meters deployed through end of 2016, with full deployment of 1,824,000 meters anticipated by end of 2017.	IEI Smart Meter Survey 2017
Dominion	VA	367,000	400,000	Dominion has completed installation of 367,000 smart meters in Virginia through 2106. The AMI business case and full deployment plans for 2.7 meters are still under development.	IEI Smart Meter Survey 2017

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
DTE Energy	MI	2,600,000	2,600,000	DTE Energy achieved full deployment of 2,600,000 smart meters in 2016.	IEI Smart Meter Survey 2017
Duke Energy	FL IN KY NC OH SC	1,769,000	7,900,000	Duke has fully deployed 729,000 smart meters in Ohio. In other jurisdictions, through the end of 2016, Duke deployed 79,000 meters in Florida; 69,000 in Kentucky; 624,000 in North Carolina; 232,000 in South Carolina; and 36,000 meters in Indiana. Full deployments are underway in Indiana, North Carolina, and South Carolina. Close to 3 million meters will be installed at the end of 2017, and 7.9 million are projected to be installed by the end of 2020.	IEI Smart Meter Survey 2017; EIA Form 861
Emera Maine	ME	120,600	120,600	Emera Maine has fully deployed 120,600 smart meters in its service territory.	EIA Form 861
Entergy Corporation	AR LA MS TX	20,000	1,918,000	Entergy has deployed 20,000 smart meters in New Orleans and is at the beginning of an enterprise wide deployment of 2,920,000 electric meters by December 2021. The company has regulatory approval in Louisiana; pending regulatory approval in 4 other jurisdictions. Deployment will be spread over 3 years, beginning January 2019 and ending December 2021. A two-year IT systems build out has begun.	IEI Smart Meter Survey 2017

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
FirstEnergy Corporation	OH PA	670,000	2,050,000	Pennsylvania Act 129 (2008) requires electric distribution companies with more than 100,000 customers to install smart meter technology to all customers by 2022. FirstEnergy subsidiary Penn Power is fully deployed with 170,000 meters. At year end 2016, West Penn Power had 98,000 smart meters deployed; MetEd had 138,000; Penelec had 264,000 deployed. Per approved deployment plans, 2,016,000 smart meters will be deployed by 2020. FirstEnergy operating company The Illuminating Company in Cleveland installed 34,300 meters as part of a pilot.	IEI Smart Meter Survey 2017
Florida Power & Light Company	FL	4,942,000	4,942,000	FPL has fully deployed 4,942,000 smart meters to residential, commericial, and industrial customers.	IEI Smart Meter Survey 2017; EIA Form 861
Green Mountain Power	VT	260,600	260,600	Green Mountain Power has deployed 260,600 smart meters to customers across Vermont.	EIA Form 826
Hawaiian Electric Company	HI	5,200	50,000	Hawaiian Electric Installed 5,200 smart meters during the first phase of its smart grid program. In August 2017, the company filed a grid modernization strategy with its state regulatory commission proposing targeted smart meter investments rather than system wide.	Docket No. 2016-0087
Idaho Power	ID OR	525,000	525,000	Idaho Power has fully deployed 525,000 smart meters across its service territory in Idaho and Oregon.	EIA Form 861

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
Indianapolis Power & Light	IN	53,000	80,000	IPL has installed 53,000 smart meters, and will strategically deploy smart meters where needed.	IEI Smart Meter Survey 2017; EIA Form 861
Kansas City Power & Light	KS MO	703,000	703,000	KCP&L completed the installation of 703,000 smart meters; 234,000 in Kansas and 469,000 in Missouri.	EIA Form 861
Madison Gas & Electric	WI	7,300	7,300	MGE installed a small-scale smart grid network, including 7,300 meters, EV charging stations, and in-home energy management systems.	EIA Form 861
Minnesota Power	MN	52,800	83,000	Minnesota Power deployed 52,800 smart meters in northeast Minnesota.	EIA Form 861
National Grid	MA NY	15,000	50,000	15,000 smart meters have been installed in Worcester, MA, for a pilot demonstration. Approximately 13,000 smart meters will be installed to support National Grid's Demand Reduction REV Demonstration in Clifton Park, NY.	IEI Smart Meter Survey 2017; EIA Form 826
NV Energy	NV	1,260,000	1,260,000	NV Energy has fully deployed 1,260,000 smart meters.	EIA Form 861
Oklahoma Gas & Electric	AR OK	873,000	873,000	OG&E has fully installed 873,000 meters: 804,000 in Oklahoma and 69,000 in Arkansas.	EIA Form 861
Oncor	TX	3,424,000	3,424,000	Oncor has fully deployed 3,424,000 smart meters across its service territory.	EIA Form 861
Orange & Rockland	NY	2,500	230,000	Orange & Rockland received approval to install 230,000 smart meters in its New York Service territory. Expected completion date is 2020.	Company Website

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
Pacific Gas & Electric	CA	5,333,000	5,333,000	PG&E has deployed 5,333,000 meters through end of 2016, and completed its SmartMeter Project in 2013. Customers with smart meters can participate in PG&E's SmartRate plan, a voluntary critical peak pricing rate plan that will help manage system load during hot summer days, and receive EnergyAlerts that notify customers when they are moving into higher-priced electricity tiers.	IEI Smart Meter Survey 2017
Pacific Power	OR	0	590,000	Pacific Power plans to install 590,000 smart meters for Oregon customers in 2018-2019.	Press Release
PECO	PA	1,649,000	1,649,000	PECO fully deployed 1,649,000 smart meters.	EIA Form 861
Pepco Holdings	DC DE MD	1,419,000	1,419,000	Pepco has reached full deployment in the District of Columbia with 303,000 smart meters installed; in Maryland, Pepco and Delmarva Power have reached full deployment of 578,000 and 213,000 smart meters, respectively. In Delaware, Delamarva Power has reached full deployment with 325,000 meters installed.	IEI Smart Meter Survey 2017
Portland General Electric	OR	863,000	863,000	PGE's smart meter program was approved by the state regulatory commission in 2008; full deployment was completed by the fall of 2010.	EIA Form 861
PPL	PA	1,426,000	1,426,000	PPL is in compliance with PA Act 129 and has fully deployed 1,426,000 smart meters in its service territory.	EIA Form 861; PA Docket No. M-2009-2092655

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
San Diego Gas & Electric	CA	1,428,000	1,428,000	SDG&E has fully deployed 1,428,000 meters across its service territory.	IEI Smart Meter Survey 2017
Southern California Edison	CA	5,069,000	5,069,000	SCE has fully deployed more than 5 million smart meters and will continue to accommodate population growth. SCE's SmartConnect program uses the meters to offer Critical Peak Pricing and Peak Time Rebate rates to customers with enabling technology.	IEI Smart Meter Survey 2017; EIA Form 861
Southern Company	AL FL GA MS	4,390,000	4,570,000	Southern Company's Georgia Power, Alabama Power, and Gulf Power are fully deployed. Georgia Power reached full deployment in 2012 and has 2,428,000 meters. Alabama Power reached full deployment in 2010 and has 1,503,000 meters. Gulf Power reached full deployment in 2012 and has 453,000 meters. Mississippi Power has installed 6,000 meters and is awaiting approval from the Public Service Commission for full deployment of 187,000.	IEI Smart Meter Survey 2017
Texas New Mexico Power	TX	240,000	240,000	TNMP achieved full deployment of 240,000 meters in Texas in 2016. It is using smart meters to facilitate outage detection/restoration and remote connect/disconnect.	EIA Form 861
United Illuminating	CT	213,000	350,000	United Illuminating has installed 213,000 of its projected 350,000 smart meters.	EIA Form 861

Electric Company	State	Meters Installed (2016)	Projected Meters Installed (2020)	Notes	Resources
Unitil	MA NH	103,000	103,000	Unitil has fully deployed 103,000 smart meters across its service territory around Concord, NH and Fitchburg, MA. It has used this technology to, among other things, implement a time-of-use pricing pilot.	EIA Form 861
Vectren	IN	0	153,000	Vectren is finalizing its AMI network design and systems integration work and starting on its field network equipment deployment. Full deployment of 153,000 smart meters is expected to be complete by summer 2019.	Docket No. 44910
Westar Energy	KS	432,000	705,000	Westar deployed 432,000 smart meters thru end of 2016 with a goal of fully deploying 708,000 smart meters by the end of 2018. As of November 2017, approximately 575,000 meters were deployed.	IEI Smart Meter Survey 2017
WE Energies	WI	187,000	187,000	WE Energies has deployed 187,000 smart meters to customers in Wisconsin.	EIA Form 861
Xcel Energy	CO	23,700	40,000	Xcel Energy has deployed 23,700 smart meters. As part of a May 2017 settlement agreement, Xcel Energy will deploy 13,000 additional meters to support integrated volt-var optimization. Pursuant to the settlement, full deployment of smart meters will not begin until 2020.	EIA Form 826; Proceeding No. 16A-0588E
Other		199,350	857,000	Limited deployments by multiple operating companies accounts for close to 200,000 smart meters deployed through 2016.	IEI Smart Meter Survey 2017; EIA Form 861
U.S. Total		53,350,000	70,000,000		

Note: Totals are rounded.

Table 3. Smart Meter Installations by Electric Company Type and State (2016)

State	Investor-Owned Electric Company Smart Meters Installed	Public Power Utilities and Electric Cooperative Smart Meters Installed	Total
AK	0	95,900	95,900
AL	1,503,000	435,000	1,938,000
AR	69,600	407,800	477,400
AZ	1,329,100	1,171,900	2,501,000
CA	11,830,000	964,000	12,794,000
CO	120,600	402,500	523,100
CT	213,000	25,800	238,800
DC	303,000	0	303,000
DE	325,000	17,000	342,000
FL	5,474,000	786,000	6,260,000
GA	2,428,000	1,807,000	4,235,000
HI	5,200	31,100	36,300
IA	1,000	172,700	173,700
ID	507,600	94,600	602,200
IL	3,460,000	220,800	3,680,800
IN	92,500	547,900	640,400
KS	666,000	294,800	960,800
KY	44,700	676,800	721,500
LA	307,000	158,000	465,000
MA	44,000	64,400	108,400
MD	2,035,000	71,000	2,106,000
ME	751,200	0	751,200
MI	3,955,000	270,200	4,225,200
MN	52,800	397,800	450,600
MO	469,000	483,700	952,700
MS	6,700	536,400	543,100
MT	200	122,700	122,900

State	Investor-Owned Electric Company Smart Meters Installed	Public Power Utilities and Electric Cooperative Smart Meters Installed	Total
NC	552,000	1,083,500	1,635,500
ND	0	117,000	117,000
NE	0	188,300	188,300
NH	74,600	84,700	159,300
NJ	13,500	24,500	38,000
NM	0	102,900	102,900
NV	1,260,000	2,000	1,262,000
NY	12,500	27,800	40,300
OH	885,000	201,000	1,086,000
OK	1,347,000	364,800	1,711,800
OR	880,300	231,900	1,112,200
PA	3,631,000	212,000	3,843,000
RI	250	0	250
SC	214,000	467,900	681,900
SD	68,600	112,100	180,700
TN	0	1,889,500	1,889,500
TX	7,074,000	2,297,600	9,371,600
UT	0	75,200	75,200
VA	367,000	384,000	751,000
VT	262,600	35,000	297,600
WA	18,000	258,000	276,000
WI	653,000	196,400	849,400
WV	1,600	6,400	8,000
WY	42,400	45,100	87,500
U.S. Total	**53,350,000**	**18,650,000**	**72,000,000**

Note: Totals are rounded.

APPENDIX

IEI 2017 Smart Meter Survey: Limits and Interpretation

Thirty electric companies (representing 54 operating companies) provided responses to IEI's 2017 Smart Meter survey. These electric companies account for roughly 41 million of the 72 million smart meters captured in this report. The remaining information on smart meter deployments was obtained from the U.S. Energy Information Administration (Forms 826 & 861), regulatory filings, and company press releases.

This report identifies general trends and examples of how electric companies are using smart meters. The report does not attempt to cover all of the ways in which electric companies are leveraging investments in their smart meters.

Smart Meter Opt-Out Policies

Several states have implemented policies that allow customers to opt out of smart meters. These customers typically pay an initial fee and a monthly opt-out fee. The number of customers who have requested to opt-out of a smart meter installation is extremely low (far less than 1 percent).

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ABOUT THE INSTITUTE FOR ELECTRIC INNOVATION

The Institute for Electric Innovation focuses on advancing the adoption and application of new technologies that will strengthen and transform the energy grid. IEI's members are the investor-owned electric companies that represent about 70 percent of the U.S. electric power industry. The membership is committed to an affordable, reliable, secure, and clean energy future.

IEI promotes the sharing of information, ideas, and experiences among regulators, policy makers, technology companies, thought leaders, and the electric power industry. IEI also identifies policies that support the business case for the adoption of cost-effective technologies.

IEI is governed by a Management Committee of electric industry Chief Executive Officers. In addition, IEI has a Strategy Committee made up of senior electric industry executives and a select group of technology companies on its Technology Partner Roundtable.

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The Edison Foundation is a 501(c)(3) charitable organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide. Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people. The Edison Foundation provides knowledge, insight, and leadership to achieve its goals through research, conferences, grants, and other outreach activities.

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