STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC	**)**	
FOR APPROVAL OF AN ADVANCED METER	**)**	**CAUSE NO. 44963**
OPT-OUT TARIFF, STANDARD CONTRACT	**)**	
RIDER NO. 59	**)**	

SUBMISSION OF CAC'S TESTIMONY AND ATTACHMENTS

Citizens Action Coalition of Indiana, Inc. ("CAC"), respectfully submits the Testimony and Attachments of Kerwin L. Olson in the above referenced Cause to the Indiana Utility Regulatory Commission ("Commission").

Respectfully submitted,

Jennifer A. Washburn

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 10th day of October, 2017, to the following:

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Testimony of Kerwin L. Olson
On Behalf of Citizens Action Coalition of Indiana, Inc.

October 10, 2017

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name, position and business address.

A. My name is Kerwin L. Olson, and I am the Executive Director of Citizens Action Coalition of Indiana, Inc. ("CAC"). My business address is 603 E. Washington Street, Suite 502, Indianapolis, Indiana 46204.

Q. Please describe your current responsibilities.

A. I have served as CAC's Executive Director since June of 2011. I am CAC's chief public policy spokesperson and its chief operating officer and am responsible to its Board of Directors for the overall program and operations management of the organization. Major priorities are established by CAC's membership at its annual meetings and broad policies are adopted by the Board of Directors at its quarterly meetings. I provide development, supervision and coordination for the implementation of policies and programs based on these priorities. My current responsibilities also include: issue and policy research; lobbying at the Statehouse; legislative outreach and education; community and media outreach; writing press releases, guest columns and op-ed columns; and community and member organizing. I am also CAC's representative on the board of the Indiana Coalition for Human Services and for other organizations and committees, and I supervise CAC's participation on numerous energy efficiency and demand-side-management collaborative oversight boards.

Q. Please briefly summarize your prior employment and educational background.

A. I studied American History at the University of Chicago from 1986 to 1989. I joined the staff at CAC twelve years ago in 2005, working in member outreach. In 2006, I became CAC's Public Outreach Coordinator, served briefly as its Phone Canvass Director in early 2008, and then served as CAC's Program Director from the beginning of April of 2008. My responsibilities included performing (and supervising others who performed) research on energy and regulatory issues. I have been CAC's primary legislative liaison since 2008. I have served as Executive Director of CAC since June of 2011. I have attended numerous workshops and seminars on energy, energy efficiency, renewable energy, coal, coal gasification, carbon capture and sequestration, biomass and bio-fuels, and nuclear energy.

Q. Have you previously filed testimony before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A. I have testified before the Commission numerous times, including in Cause Nos. 43114 IGCC-4S1; 43114 IGCC 5; 43114 IGCC 6; 43114 IGCC 7; 43114 IGCC 9; 43114 IGCC-4S3; 43114 IGCC-15; 43912 (NIPSCO DSM); 43967 (Indiana Gasification); 44067 (SIGECO Dense Pack); 43912 (NIPSCO Feed-In Tariff); 43653 (Duke CCS study); 43669 (gas universal service programs); 43839 (SIGECO rates); 44310 (Self-Direct Investigation); 44339 (IPL CCGT and HSS Refueling); 44441 (Implementation of SEA 340); 44478 (IPL EV); 44720 (Duke TDSIC); 44765 (Duke CCR); 44872 (NIPSCO CCR); 44910 (Vectren TDSIC);

and 44945 (IPL 2018-2020 DSM). In addition, my duties require me to testify before several of the Indiana General Assembly's House and Senate committees and participate in panel discussions in public forums.

Q. What did you do to prepare yourself to testify for this proceeding?

A. I reviewed the direct testimony filed and discovery answered by Duke Energy Indiana ("Duke," "DEI," or the "Company").

Q. Please summarize DEI's requested relief.

A. DEI seeks tariff approval to assess charges to those residential and small commercial customers who choose to opt out of smart meter installation on their homes and small businesses. The opt out charges consists of a one time payment of $104.96 and thereafter monthly payments of $28.59 for the duration of the customer's connection to DEI's system.

Q. What is your position regarding this proposal?

A. DEI customers should be able to maintain their status quo, i.e. opt out of smart meter installation and continue to have their current meters read without charge. DEI's proposed opt out charges should be denied. Just some of the reasons for charge denial include:

- Inadequate notice to customers;
- Proposed charges are punitive in nature;
- Proposed charges are unfair, one sided, cherry picking form of ratemaking that results in double recovery and are unnecessary;

- DEI ignores other billing options that could be applied to minimize the need to read meters of opt out customers, maintain their customer satisfaction, and benefit DEI;
- There is no other customer subsidization from leaving opt out customers on current meters; and
- The alleged costs may not even exist and are just represent a between rate cases cost of doing business.

II. INADEQUATE NOTICE

Q. How did DEI inform customers about the installation of smart meters?

A. To the best of my knowledge, DEI's process was to send residential and small commercial customers the postcard approximately two weeks prior to installing a smart meter on their property. That postcard is included in my testimony as Attachment KLO-1. It's my understanding that DEI also did outreach with the media and met with leaders in local communities prior to deploying smart meters in those communities.

Q. Does the notice inform customers that they can choose to not have a smart meter installed?

A. No, it does not. Nowhere on the postcard does DEI inform customers that they can choose to opt-out and not have a smart meter installed on their home or business. It is only after a customer calls the 800 number on the post card that the customer might possibly learn that they may opt out of having a smart meter installed.

Q. DEI does provide a web address, www.duke-energy/SmartGrid, on the postcard. Does that link provide any information regarding a customer's ability to opt-out of a smart meter installation?

A. Not that I could locate. In fact, the FAQ section on smart meters asks the question, "Who is receiving a smart meter?" The answer provided is "***All*** Duke Energy customers, both residential and commercial, will receive a smart meter," with no language stating that customers who do not want a smart meter can opt-out (emphasis added).

Q. Does DEI give customers notice of its intent to impose extra charges on opt out customers?

A. No, neither the postcard nor calling the 800 number advises the customer that DEI is seeking to impose a $104.96 opt out fee and a $28.59 per month fee thereafter on opt out customers. First, it should be noted that the opt-out charges are only proposed at this point in time. The Commission has not approved them. Furthermore, DEI began wide-scale deployment before even seeking approval for the opt-out charges at issue in this proceeding. DEI, and any other regulated utility, should be required to seek these approvals before beginning installations, not after. That is fundamentally unfair to the captive customers of a monopoly.

In my view, this notice process denies DEI customers reasonable information that would be relevant and necessary for the customer to determine if they want to opt out of smart meter installation. Rather than providing customers with full, fair, and proper notice, DEI's framework seems to be geared toward maximizing smart meter participation and then later financially forcing people to accept a smart meter, or financially punishing people who continue to want to opt out.

Q. In your opinion is DEI's smart meter customer notice framework likely to cause customer dissatisfaction?

A. Yes, it is. DEI has on numerous occasions held itself out as seeking to provide customers with an array of billing options that creates or enhances customer satisfaction. In my opinion, the manner in which this smart meter deployment has been described to customers and the requested onerous opt out charges will create strong customer dissatisfaction amongst Hoosiers who for reasons of privacy, health, security or any other reasons prefer to opt out of having these communication devices installed on their property.

Furthermore, many concerns around customer privacy and cyber security exist regarding smart meters. Indeed, CAC witness Tyson Slocum discussed the need to address cyber security and privacy concerns prior to any DEI smart-meter rollout in CAC Exhibit 1, Attachment TS-1, filed with the Commission in Cause No. 44526. (Attachment KLO-2). Many customers believe that smart meters invade the privacy of their homes by giving the utility direct access to continuous appliance energy usage and home energy usage in total. They are also concerned that because the utility's computers can turn service off via a smart meter, and the receipt of electric service becomes susceptible to hackers. Customers who may not want a smart-meter as a result of these unaddressed concerns, but received one anyway, will be displeased. Also, some customers are concerned about purported health risks from smart meters.

III. THE CHARGES ARE PUNITIVE

Q. Why do you characterize DEI's proposed charges as punitive?

A. As I previously discussed, the notice does not inform customers that they may opt out of the smart meter program, but by doing so, they unknowingly expose themselves to DEI's proposed \$104.96 and \$28.56 per month charges. Imagine your reaction if for security reasons, privacy reasons, or any personal reason, you told DEI to not install a smart meter on your house, and they temporarily did not install one. Then some weeks later, assuming DEI receives approval of these proposed charges, DEI contacts you and says you will have to pay \$104.96 upfront plus \$28.56 per month thereafter, or you now must consent to accepting the smart meter you did not want and was not installed on your home in the first place. I think opt out customers would be furious, and rightfully so. The framework DEI has built here will breed customer dissatisfaction. DEI should have designed its program to give customer full disclosure before they make a decision. They need and deserve full disclosure.

Q. Given that monopoly utility regulation is intended to mimic the forces of competition in setting rates, what impact in your opinion does that have on DEI's proposed charges?

A. The requested charges should be denied. They are oppressive. Imagine you purchase a competitive service for on average \$120.46 per month, the amount of DEI's bill for 1000 kWh per month according to the most recent IURC bill survey. Now imagine among competing service providers that your provider tells you that they intend to charge you \$105 plus an additional \$30 per month thereafter in order for you to continue to be billed in the same manner as you are billed today for the same service. In just the first year alone, your annual billed expense would increase by 32%. Any sensible person faced with that would change competitive service providers. But here the only ratepayer source of that competitive force is reasonable rate regulation.

Q. Despite the lack of reasonable notice to DEI's customers, how many smart meter installations has DEI put on hold for current Indiana opt out customers?

A. In his testimony, Mr. Brown anticipated 0.1% customers would participate in Rider No. 59 equaling about 836 Indiana customers out of 836,000 total customers. Yet as of September 26, 2017, with approximately 275,000 smart meters deployed, approximately 0.2% of customers, or a total of 530, had put smart meter installation on hold. DEI Response to OUCC Set 6.1 (Attachment KLO-3). Thus, as of September 26, 2017, with only 275,000 of the total 836,000 smart meters deployed, this is approximately twice the number of opt outs that Mr. Brown would have expected so far.

IV. <u>CHARGES ARE UNREASONABLE AND UNNECESSARY</u>

Q. Why in your opinion is DEI's proposal to charge customers $104 set up fee and $28.56 per month forever to opt out unreasonable and unnecessary?

A. In my opinion, this is one of the worst forms of ratemaking proposals possible. It is certainly one of the worst I can recall. It attempts to impose onerous costs on a selected small group of residential customers merely for them to maintain their status quo current metering and billing while ignoring the cost savings that the new AMI program is expected to achieve. It ignores the revenue already in base rates to cover this meter related area of O&M and is based on a calculation of cost without any real showing that the alleged new, incremental dollar costs will even be incurred.

Q. Please explain how opt out related costs are already recovered in DEI's base rates.

A. Mr. Brown estimates IT system costs of $150,000. Obviously IT system costs are costs that would have already been included in DEI's base rates at the time of its most recent retail rate case. Mr. Brown proposes that 10% of the IT costs be included in the initial charge and the remaining 90% in the monthly recurring charge. Brown at 7. He also testified that there will be metering service costs to process work orders, perform manual meter reading, route analysis, disable meter radios, and perform meter exchange to a non-standard, non-communicating meter. Those costs are also included in the $104.96 initial fee. There again, administering residential and small commercial metering services is an expense with matching rate revenue that would have been included in current rates at the time of DEI's most recent retail rate case.

Regarding the $28.59 monthly fee, Mr. Brown says that can be broadly characterized as IT system costs and meter reading costs. The manual, opt out monthly meter reading costs includes both on and off cycle reads. Obviously, DEI's current base rates contain a revenue requirement for meter reading. The amount currently included in base rates for residential meter reading is approximately $4,166,000 annually. DEI Response to OUCC 2.1-A (Attachment KLO-4). If, as Mr. Brown projects, only 836 of DEI's 836,000 customers in the future need to have their meters read, 99.9% of that $4,166,000 meter reading expense embedded in rates currently would be available to offset the cost of reading the 836 opt out meters per month. Simply put, the avoided meter reading expense is enormous when compared to the very small expense of maintaining status quo meter reading for the projected 836 customers. Even if there are twice as many opt outs or more, the revenue in current rates for meter reading far exceeds the cost of continuing to read opt out customer meters.

Q. Is it anticipated that there will be AMI savings that dwarf any costs arguably associated with smart meter opt outs?

A. Yes, DEI previously indicated in Cause No. 44720 that net savings associated with its AMI project is expected to be $39,690,000 over seven years. DEI Response to OUCC 1.11 (Attachment KLO-5). Obviously, those projected savings is more than enough to offset the relatively tiny cost of maintaining status quo metering and meter reading for the estimated 836 opt out customers, or more. Furthermore, DEI states in discovery that DEI will retain those benefits until DEI files its next base rate case. *Id*.

Q. Are there other instances where DEI has incurred meter related costs where it did not try to get authority to charge extra to customers?

A. Yes, DEI has 22,147 AMR meters, meters that can be read without looking at the numbers on the meter dial via a handheld device if the meter reader is close enough. DEI installed those on its own initiative due to meter access or employee safety concerns. Thus, when it came to incurring additional costs to solve problems of access to meters for the avoidance of safety concerns like mean dogs, locked gates, etc., DEI did not choose to attempt to have a single issue rate recovery for that and instead just did as it should and treated it as an ordinary cost of operations. DEI Response to OUCC 3.3 (Attachment KLO-6).

Similarly, DEI customers are not charged extra to replace meters that cease to operate properly, yet here, for opt out customers that simply want to continue relying upon their properly operating, existing meter, DEI wants to place onerous charges on those customers. DEI Response to OUCC 3.4 (Attachment KLO-7).

Similarly, DEI does not give any financial credit to opt out customers that want to keep their non AMI meter with 35 year lives, instead of having them replaced with AMI meters that have an anticipated 15 year useful life. DEI Response to OUCC 3.6 (Attachment KLO-8). In other words, DEI says it can expect to replace smart meters every 15 years, while customers remaining on current meters only may only need their meters replaced every 35 years. That longer life of opt out customer meters would create a potential capital cost and O&M savings for DEI.

V. OTHER BILLING OPTIONS THAT COULD REDUCE OPT OUT CUSTOMER METER READING EXPENSE

Q. Has DEI harnessed any of its current alternative billing option plans by which it could reduce its alleged meter reading costs for opt out customers?

A. No, it has not and for a company that prides itself on creating customer satisfaction in part by offering an array of customer billing options, it again leads me to think their focus is largely on forcing customers to accept a smart meter whether they like it or not, rather than trying to meet their energy preference needs of customers who prefer to opt out.

Q. How could current DEI billing options reduce meter reading costs for opt out customers?

A. DEI offers residential customers monthly budget billing. There, the gist of it is customers with adequate payment and billing history pay the same amount every month with possible mid-year and end of year adjustment or year true-up. Mid-year, the budget bill amount might be increased based on actual usage. End of year, any under collection may be charged or blended into the next year's monthly budget billing amount. For opt out customers who are put on Budget Billing, that could mean their meters would not need to be read every month, and perhaps read just twice a year, which could also decrease even the current cost to read opt out meters.

Similarly, DEI offers a fixed bill option "Your FixedBill." There, the gist of it is for customers with adequate past billing records and payment history, DEI can run a computer program that yields what the customers' annual electric usage and amount to be billed would be. The Your FixedBill program does not guarantee customers the lowest cost possible, but offers the certainty of paying the same amount each month without year end budget bill type true up. DEI might annually charge a little more than it would have with regular billing, but might charge a little less.

Here again for opt out customers those who chose to participate in the fixed bill program, their meters may not need to be read every month, offering meter reading savings. Please note, those billing programs are not substitutes for customers opting out of smart meters, but they may be a means to reduce metering expense.

VI. <u>SUBSIDIZATION IS NOT A LEGITIMATE CONCERN</u>

Q. DEI contends its suggested $104.96 charge and $28.56 monthly charge are needed to avoid other customers subsidizing opt out customers. Do you agree with that assertion?

A. No, I absolutely do not agree with DEI's "subsidization" theory, for many reasons.

First, the total amount of DEI's alleged IT and meter costs is tiny and immaterial in comparison to DEI's annual revenue requirement allocated among the various customer classes. DEI's annual operating revenue exceeds $4 billion dollars. DEI's alleged opt out costs are so small they likely would be susceptible to being extinguished by the slight rounding numbers in a cost of service / rate design study.

Second, as I previously testified, DEI was given reasonable revenue in base rates to pay for IT and meter O&M at the time of its last rate case. Subsidization was addressed in the cost of service study and rate design at the time DEI's last base rates were set. To cherry pick the alleged small cost of relatively few customers opting out of smart meters outside the context of a base rate case is not a subsidization issue. It is just to cast a chilling effect on customers' ability to opt out.

Third, the AMI savings DEI previously touted and the avoidance of paying meter reading costs for 98% or 99% of DEI's residential and small commercial customers is immensely greater than the alleged opt out costs.

Fourth, DEI is proposing the worst form of rate making imbalance. Even assuming that its professed opt out IT and metering costs are accurate and legitimate, DEI does not file to reduce its rates when it successfully reduces an area of O&M and creates savings. DEI does not send its operational savings to customers between rate cases. Yet, here DEI wants a special charge assessed to a relative few residential customers at a punitive level for an alleged small expense. DEI creates a rate scenario of all new savings provided are for the utility, all new costs no matter how small can be charged to rate payers on a single issue basis in separate filings between rate cases.

Fifth, if DEI is granted this single issue rate adjustment between base rate cases, it opens the door for other stakeholders to argue for reallocation of rates when DEI has a successful program of materially reducing O&M costs, receives a large judgment against a third party, lands a new very large load industrial customer or other major reductions to costs that occur or new revenues are received. The between rate cases single issue ratemaking gate that DEI attempts to open here is a gate that if opened, regulatory balance and fundamental rate making would require it swings both ways to allow consumer advocates to pursue single issue rate reductions for DEI cost reduction and new revenues, causing significant regulatory burdens.

Sixth, meter readers reading the meters of opt out customers in person and DEI sending resulting bills to customers is simply a continuing cost of doing business. If DEI choses to change its internal IT framework for manually meter read meters, that too is simply a between rate cases change in the cost of doing business. It is not an instance of rate subsidization.

VII. <u>OPT OUT CUSTOMERS SHOULD BE ABLE TO KEEP THEIR CURRENT METER AND NOT HAVE A TRANSMITTER DISABLED AMI METER INSTALLED.</u>

Q. Why are you concerned that DEI opt out customers be able to keep their current meter rather than have a disabled AMI meter installed?

A. Mr. Brown testifies that "At the Company's option, meters to be read manually may be either and AMI meter with RF functions turned communication capability disabled or other non communicating meter." Brown at 6. There are multiple concerns here.

First, contrary to Mr. Brown's testimony just cited, in discovery DEI stated it plans to install smart meters on the homes of all opt out customers with the transmitter disabled. DEI Response to OUCC 1.6 (Attachment KLO-9). Many folks who disfavor smart meters simply do not want them on their homes in any way. Their current meter works fine, and they want to keep it. Second, Mr. Brown at p. 6 shows the face of a disabled smart meter and testifies it says "RF OPTOUT." However, as his photo on p. 6 shows it does not say that. What it says is indiscernible. Moreover, as his picture shows, if that is what the transmitter turned off meter screen will say, then the customer cannot read their energy use on the meter screen, as they are now able to do. For many customers, looking at the usage numbers on the meter screen is an easy way to confirm bill accuracy and keep track of energy use. In short, within the bounds of reason, the Commission should give the relatively few opt out customers what they want, which is to retain their metering status quo: their current meter, without additional charges.

VIII. <u>ALLEGED DOLLAR COSTS MAY NOT EVEN EXIST</u>

Q. Why may DEI's alleged opt out costs not even exist?

A. The portion of those costs that relate to labor may not really occur as labor is often supplied by salaried employees or contractors who work for set payments. In other words, a new assignment to work on the billing IT system may just be the next task on their plate and not generate additional payment to the employee or her employer. Or continuing to read some meters may mean the contractor will continue to get paid per meter read, nothing more. DEI's business that it can calculate dollar amounts for expenses does not mean those dollar amounts would actually be paid.

IX. CONCLUSION

Q. What are your conclusions?

A. For the many reasons I have stated, those who chose to opt out of smart metering should be allowed to do so at no cost. The charges DEI proposes should be denied.

Q. Does this conclude your testimony?

A. This is what I offer at this time. CAC has pending, unanswered discovery under dispute and for that and other reasons I may need to supplement my testimony.

VERIFICATION

I, Kerwin L. Olson, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

______________________________ __October 10, 2017________________

Kerwin L. Olson Date

ATTACHMENT KLO-1

We're upgrading the electric meter at your home or business.

In the next few weeks, we will be in your area to install new digital smart meters. Some benefits of the new meters include access to more information about your energy usage online and fewer estimated bills. Here's what you can expect:

- For your safety and security, every Duke Energy employee or contractor carries a picture ID card.
- Our technician will install the new meter at your home or business. If no one is available, the technician will leave a note saying the installation was successful. If the technician was not able to access the meter, he/she will leave a note indicating an appointment is needed, along with instructions to schedule an appointment.
- The installation process may cause a brief interruption in service.

For more information, visit
duke-energy.com/SmartGrid.

We appreciate your cooperation
as we bring you the latest digital technology that will give you more ways to manage your energy use and costs.

Questions about this meter change?
Call us toll-free: 855.903.8513
Monday – Friday, 7 a.m. - 7 p.m., Saturday 10 a.m. - 2 p.m.

DUKE ENERGY®

ATTACHMENT KLO-2

THE NEED FOR ESSENTIAL CONSUMER PROTECTIONS

SMART METERING PROPOSALS AND THE MOVE TO TIME-BASED PRICING

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Consumers Union
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EXECUTIVE SUMMARY

There is widespread consensus that the U.S. distribution and transmission systems for vital electricity service need to be modernized and upgraded. This modernization has been recently promoted under the rubric of the Smart Grid. The Smart Grid vision has three primary parts: (1) new communication and digital sensors and automation capabilities for the distribution and transmission systems; (2) new digital metering systems for all customers; and (3) direct interfaces between the new metering systems and customers through in-home technologies.

The potential benefits of the Smart Grid are typically presented as improving distribution service (by lowering operational expenses and improving the operation of the distribution and transmission grid to make service more reliable) and reducing generation supply costs and prices (by reducing peak load usage and usage overall). In addition to these potentially important benefits, Smart Grid investments are also linked to the ability to integrate new renewable resources and the expected increase in electrical powered vehicles. However, all of these benefits must be carefully proven out in a state's review of the merits of any Smart Grid proposal.

Congress appropriated $4.5 billion to modernize the electric grid as part of the 2009 American Recovery and Reinvestment Act (ARRA), of which over $2 billion has been allocated to grants for advanced metering projects. At the state level, most utility filings before state regulators have tended to focus on the new metering investments and pricing programs, although there are some limited demonstration projects that are not linked to new metering systems. Given the state and federal emphasis on metering, this paper also focuses on the advanced or smart metering component of the Smart Grid vision.

Smart meter adoption is not risk-free. Stranded costs (relating to the premature abandonment of the existing metering system), unrealized consumer benefits, and the potential for pricing proposals that may be harmful to some customers, as well as the potential for increased disconnections if consumer protections are not maintained or enhanced, are a few of the problems that must be addressed and worked through. Our groups' concerns about the lack of state-level consensus on the proper level of regulatory scrutiny of, and consumer protections associated with, smart metering and pricing proposals contribute to our recommendation that the Administration should elevate these concerns in its consideration of Smart Grid policies and smart metering initiatives in particular. We also recommend the Administration recognize and incorporate the primacy of robust benefit cost analysis from a consumer perspective in its Smart Grid policies overall and with respect to smart meter policies in particular and promote key consumer protections to accompany smart metering proposals.

The adoption of smart meters should be carefully examined and considered in light of the following key concerns and, where implemented, should be accompanied by several essential consumer protections. We recommend that the Administration support the following consumer protection policies, which are described in more detail in this paper:

1. Smart meter proposals must be cost-effective, and utilities must share the risks associated with the new technologies and the benefits used to justify the investment.
2. Time-of-use or dynamic pricing must not be mandatory; consumers should be allowed to opt-in to additional dynamic pricing options.
3. Regulators should assess alternatives to smart meters to reach the same load management goals, particularly direct load control programs.
4. Smart meter investments should not result in reduced levels of consumer protections, especially relating to the implementation of remote disconnection, and traditional billing and dispute rights should be retained.
5. Privacy and cyber-security concerns must be addressed prior to a smart meter rollout.
6. Utilities and other policymakers should include comprehensive consumer education and bill protection programs in any evaluation or implementation of smart meter proposals.
7. Investments in Smart Grid need to be verifiable and transparent and the utilities need to be held accountable for the costs they want customer to pay and the benefits they promise to deliver. Costs should be reasonable and prudent.

THE NEED FOR ESSENTIAL CONSUMER PROTECTIONS

SMART METERING PROPOSALS AND THE MOVE TO TIME-BASED PRICING

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I. INTRODUCTION

There is a widespread consensus that the U.S. distribution and transmission systems for vital electricity service need to be modernized and upgraded to handle not only load growth, but the integration of renewable resources and the potential for a significant increase in electric-powered vehicles. This modernization has been recently promoted under the rubric of the Smart Grid. The Smart Grid vision has three primary parts: (1) new communication and digital sensors and automation capabilities for the distribution and transmission systems, designed to make the grid more reliable and capable of integrating renewable and local-level distribution resources, as well as the potential growth in electric-powered vehicles; (2) new metering systems for all customers, designed to be a platform for operational efficiencies and new pricing programs to stimulate peak load reduction and lower consumption; and (3) direct interfaces between the new metering systems and customers through in-home technologies that enable customers to "see" their usage profile in real time and monitor or control specific appliances.

The potential benefits of the Smart Grid are typically presented as improving distribution service (by lowering operational expenses and improving the operation of the distribution and transmission grid to make service more reliable) and reducing generation supply costs and prices (by reducing peak load usage and usage overall). A utility's Smart Grid proposal may or may not evaluate all of these potential benefits, but typically smart metering proposals focus on operational savings and the potential for generation supply benefits as a result of demand response or peak load reduction programs. However, some utilities have combined proposals to include not only smart metering, but investments in the distribution system itself to improve reliability of service. In addition to these potentially important benefits, Smart Grid investments are also linked to the ability to integrate new renewable resources and the expected increase in electrically powered vehicles. However, all of these benefits must be carefully proven out in a state's review of the merits of any Smart Grid proposal.

At the state level, utility filings before state regulators have tended to focus on the new metering investments and in many cases, the pricing programs. As a result, this paper primarily focuses on the advanced or smart metering component of the Smart Grid vision.

It is our intent to make recommendations that will guide policies and decisions about the implementation of smart meters in a manner that will serve the goals and objectives of modernizing the electricity infrastructure while protecting consumers.

II. BACKGROUND

The Smart Grid is often described in terms of new technologies that are predicted to lower utility operational costs, electricity usage, reduce peak load demand, allow for the integration of renewable energy resources and distributed generation, allow for the penetration of electric vehicles, reduce greenhouse gas emissions, and improved reliability. However, most states are currently faced with proposals for smart metering and dynamic pricing programs[1] and have not typically considered system-wide and comprehensive Smart Grid investment plans that include the modernization of the distribution and transmission system.

The jurisdictional nature of the country's electric and natural gas utility services has implications for Smart Grid. The Congress has endorsed several aspects of the Smart Grid vision in the Energy Policy Act of 2005 and further in the Energy Independence and Security Act of 2007. Both of these energy bills amend the Public Utilities Regulatory Policies Act (PURPA) to seek state review of specific federal policies and decide whether to adopt such policies and, if so, how such policies can be implemented in each state. These policies include installation of smart metering and offering various kinds of time-based or dynamic pricing to any customer upon request. However, there is no federal regulation of public utility investments, rate recovery policies, and utility pricing programs for retail customers. The federal jurisdiction as embodied in the authority of the Federal Energy Regulatory Commission (FERC) is directed to wholesale services and utility investments in the bulk transmission and natural gas pipeline systems. FERC also has authority over the policies and operations of the regional transmission operators or RTOs, which direct the traffic on the bulk transmission network and have a significant role in the manner in which prices are set for wholesale electricity and natural gas sales. State jurisdiction is reserved for the regulation of intrastate monopoly functions (even where generation has been made a competitive service, the distribution utility is fully regulated at the state level) and the rates that end-use customers pay for essential electricity and natural gas service.

Thus, while the federal policies may support Smart Grid objectives and promote the investment in certain Smart Grid technologies, such as smart metering, only state regulatory commissions can review and approve filings by investor-owned electric utilities to invest in such technologies and recover the costs in rates from its customers.[2] The federal role in promoting Smart Grid investments is limited to guidance, assistance in national standards development, or contingent on federal grant authority, research and development, such as the funding for Smart Grid investments and demonstration grants in the American Recovery and Reinvestment Act. Ultimately, privately owned utilities can recover the costs of any new investments in their rate base or change the method by which residential customers are charged for basic electricity service only by filing an application with the state regulatory commission.

The approval of rate increases or new pricing structures typically occurs after notice and public opportunity to participate in formal hearings where evidence is presented and formal decisions are made by regulators in a judicial type atmosphere and under judicial type procedural rules. It is in the context of these state regulatory decisions that the promised benefits of Smart Grid and smart metering investments must be judged against the evidence relating to costs and benefits to consumers. Ratepayers pay for investments in smart meter and Smart Grid technologies, and these investments affect their usage, rates, bills, equipment and appliances in their homes and businesses.

III. EFFECTIVENESS OF SMART METERS AND DYNAMIC OR TIME-BASED PRICING PROGRAMS

The implementation of smart meter programs is usually accompanied by proposals to consider dramatic changes in the way basic electricity service is priced for residential customers. Recent pilots have attempted to test consumer response to pricing options, including dynamic pricing, critical peak pricing and peak time rebates. Some of these pilots have also included testing of "smart" thermostats (e.g., thermostats that can accept a radio or wireless signal for direct load control) and in-home display devices. Recent smart metering and pricing pilot programs[3] point to the following conclusions:

A. Some pilots to date demonstrate the ability of smart meters and dynamic pricing to reduce the peak demand of residential customers. The recent dynamic pricing pilots are inconclusive as to the long term or overall reduction in energy usage.

The results of recent dynamic pricing pilots have shown that residential customers who volunteer for these pilot programs will lower peak load usage in response to either high critical peak prices or the offer of a rebate or credit and deliver significant peak load reductions during the pilot period.[4] These programs tend to shift usage from peak periods to off-peak periods rather than reducing total energy consumption.

The California statewide pilot program was conducted in 2003-2004 and gathered data for customer participation in a variety of dynamic rate options over a 15-month period. The pilot tested a Time-of Use (TOU) rate with a very high peak period price, a fixed price Critical Peak Price (CPP) component grafted onto the existing inverted block rate structure (the default rate structure for all residential customers in California) and a variable price CPP. The pilot documented a significant reduction in peak load usage with the CPP options. The evaluation found that the modest overall usage reduction that was recorded for TOU-only customers during the first year almost completely disappeared by the second year. With regard to low-income customers, the evaluation determined that the elasticity of demand for these customers was essentially zero.[5] That is, low income customers in this study exhibited very little response to higher electricity prices. These limited findings, if replicated elsewhere, could be troubling because where there is inelasticity of demand for any subset of customers, the costs of the new metering system are not offset by any customer benefits in the form of lower bills.

Extrapolating usage data from voluntary, multi-month pilots into multi-year predictions for the entire population may not yield valid predictions. The risks of relying on a four-month pilot program to project system wide benefits under a full deployment of smart metering over a 15-year cost-benefit analysis to justify the utility's proposed smart meter investment were graphically described by the Maryland Public Service Commission in its recent order rejecting BG&E's original smart meter proposal:

> BGE's pilot program solicited volunteers randomly through the mail and fully 20-25% of potential customers declined to enroll in the program, which in our view does not bode well that ratepayers will respond as enthusiastically as BGE anticipates. Pilot participants could have been skewed towards those more committed to energy conservation. Also, unlike the current Proposal, participants in BGE's Summer 2008 Pilot program received

either $100 or $150 in compensation. And despite the existence of a control group, participants in the pilot programs were more likely than the typical ratepayer to own their own home, a swimming pool, a dishwasher, programmable thermostats; to possess a college education; to earn over $75,000; and to use central air conditioning.

BGE's past experiment with voluntary time-of-use rates revealed a steady decline in participation since its peak in 1999. We do not purport to know the extent to which ratepayers ultimately will participate in a dynamic pricing schedule such as the one BGE proposes, but we do not have a high level of confidence in BGE's predictions on that score, and we do not believe BGE's ratepayers should exclusively bear the risk that participation will fall far short of the Company's projections.[6]

The recently concluded BG&E dynamic pricing pilot referenced above documented that customers exposed to both critical peak pricing, peak time rebates, as well as an in-home display to alert the customer to the onset of more expensive power hours did reduce *critical peak usage* on average in response to these educational programs and price signals. However, the *average usage* for the customers participating in the dynamic pricing programs did not decrease.[7] Customers typically shifted, rather than reduced, their overall usage. California's statewide pricing pilot documented the same result.[8] The recently completed CL&P pilot in Connecticut also documented that overall usage reductions are either minimal or not evident at all, even though the pilot subsidized in-home displays. [9]

The reduction in peak energy usage can result in lower bills if the customer's rebate is in excess of the cost of the electricity used during off-peak hours or if the customer is able to incur bill savings by shifting usage from peak to off-peak hours and these rebates or savings offset the costs related to the smart meter installations.

It is possible the new technologies under development will make overall usage reduction a reasonable objective, such as more smart thermostats or other residential energy management systems coupled with appliance automation, as will the use of storage technologies such as off peak cold storage to address air-conditioning usage. Furthermore, other customer feedback studies have documented overall usage reduction, some relying on dynamic pricing, but some of these studies rely on direct load control technologies or educational initiatives that are not linked to smart metering.[10] Nonetheless, it is likely that additional enhancements beyond the metering systems themselves will be needed to reduce overall electricity consumption. Additional devices (such as in-home displays) may increase the costs to consumers beyond the metering systems themselves and may threaten the affordability of electric service for lower income customers.[11]

B. *Rebates can be an effective way to lower the risks associated with time-based pricing options.*

While the initial pilots (such as the California Statewide Pilot Program) focused on changing the customer's underlying price structure for basic electricity service, most recent pilots have tested the option of a Peak Time Rebate (PTR). Peak Time Rebate (PTR) programs have achieved a significant level of peak load reduction without changing the underlying rate structure. The PTR programs offer a credit or rebate to customers who reduce usage during critical peak hours and the value of that peak reduction is not only passed through to participating customers in the form of a credit on the bill, but to all other customers when the value of this peak time reduction is monetized in the wholesale market and returned to retail customers by the entity that is aggregating this demand response (which is likely to be the utility in most cases). These pilot programs have demonstrated that residential customers can deliver the same or similar level of peak load reduction if promised a rebate or credit compared to the customers who were on critical peak prices.

Furthermore, the objective of obtaining a significant level of peak load demand reduction can be met without an expensive new metering system. For example, Baltimore Gas & Electric's ("BG&E") Peak Rewards Program[12] in Maryland initiated a successful Smart Grid program that relied on the use of "smart thermostats" installed in customers' homes with central air conditioning or a heat pump system. The Peak Rewards Program utilized a communication system between the utility and the thermostats, *but did not require new metering infrastructure or time-of-use pricing models*. The Maryland Public Service Commission ("PSC") discussed the Peak Rewards Program in its report to the Maryland Legislature:[13]

> The greatest success from the pre-EmPower Act period came from a BGE program, now called Peak Rewards. Peak Rewards is a voluntary program in which customers can agree, in exchange for bill credits, to allow BGE to install a device through which BGE can turn down the customer's air conditioning on peak demand days. As approved, Peak Rewards is surcharge-neutral, even to non-participants, because BGE can fund it with the proceeds from bidding the resulting demand response into the RPM capacity auctions. As a result of Peak Rewards, BGE bid 495 MW of demand response into the May 2008 auction—effectively a power plant's worth of demand response that substitutes for an equivalent amount of new generation. Having approved Peak Rewards, the Commission directed Pepco, Delmarva, Allegheny and SMECO on January 3, 2008 to file similar demand response programs and, with the exception of Allegheny, all of them now have programs of their own.

C. *Total costs have not been included in estimates of customer savings under pilots.*

The estimated or calculated bill impacts as a result of the dynamic pricing programs offered in the recent pilot programs in some cases, may not reflect the entire costs of implanting smart metering, communication systems, new billing systems, consumer education and customer care costs, or other expenses associated with making significant changes in how customers pay for essential electricity service. In addition, many of the pilots provided in-home devices at no cost to the participating customer whereas utilities have not yet proposed any full scale deployment of in-home devices as part of their smart metering proposals. The evaluations of programs in which the total costs have not been reflected do not answer the question of whether the bill savings reported in the pilots and which appeared to satisfy most participants will actually occur once the surcharge or higher rates are included in customer bills to pay for the new metering system.

D. The impact of dynamic pricing on vulnerable customer groups has not been adequately studied.

None of these pilot programs have gathered and reported statistically valid data on low use, elderly and medically frail customers who may require a higher usage of electricity on hot summer days in order to prevent significant health issues and mortality.

Having access to affordable heating in the winter and cooling in the summer are vital to the health and safety for many people. The potential health risk of peak pricing is especially dire in the summer. A seminal study of the July 1995 heat wave in Chicago, Illinois that resulted in 739 deaths documented that some elderly residents refused to use fans or air conditioners in part because of their fear of higher electric bills that would be unaffordable in the future. Almost three-quarters of the victims were over age 65.[14] Unfortunately, similar tragedies occur throughout the U.S., although in lesser numbers in any one location. Heat waves in the U.S. result in more deaths than all natural disasters combined. According to the Centers for Disease Control and Prevention a total of 3,442 deaths resulting from exposure to extreme heat were reported in the period 1999-2003, an annual average of 688.[15] The victims of excessive heat are primarily elderly, poor, socially isolated, and/or infirm. These customers are often unable to afford an electricity bill that requires significant reliance on air conditioning systems and the use of fans, yet such systems are absolutely vital to their ability to withstand the impact of heat over any length of time in urban environments.

A recent paper issued by AARP documents the close connection between affordable home energy and potential adverse health impacts when energy is not affordable:

> Unaffordable home energy bills pose a serious and increasing threat to the health and well-being of a growing number of older people in low- and moderate-income households. For many of these households, high and volatile home energy prices jeopardize the use of home heating and cooling and increase the prospect of exposure to temperatures that are too hot in summer and too cold in winter. The potential consequences of exposure to such temperatures and related financial pressures include a host of adverse health outcomes, such as chronic health conditions made worse, food insecurity, and even the premature death of thousands of people in the United States each year.[16]

The importance of affordability for vulnerable customer groups is why all the consumer groups that have authored this paper support national policies that lessen the cost of energy. Therefore, any dynamic rate design should be strictly voluntary, and the value proposition of the rate design should make electricity more affordable, not less, for those that opt-in to such a rate.

E. The impact of dynamic pricing on low-income consumers has not been adequately studied.

Consumer advocates have called for more studies on the impact of time-based pricing on low-income compared to other customers and have consistently raised concerns about the lack of pilot programs that have specifically enrolled and monitored low income customer reaction to dynamic pricing.[17] On average, low income residential customers use less electricity than higher income customers, but spend a higher percentage of their income on electricity.[18] Furthermore, the penetration of older and less efficient appliances is much higher for low-income households,[19] who cannot afford to upgrade and purchase newer appliances even with utility rebates.[20]

The published evaluations of recent pilot programs, such as those cited in this paper from California, Maryland, Connecticut, and the District of Columbia, have documented that in general low income demand response results were significantly less than other residential customers. Several of these pilots did not explicitly enroll a statistically valid sample of known low income customers and relied on voluntary survey information obtained after the pilot was conducted to determine "low income" status based on declared household income. Finally, we are concerned about a recent report published by the Institute for Energy Efficiency (a sister organization of the Edison Electric Institute) that presents data on low income customer results from several recent pilot programs because the data relied upon in this report is not included in the publicly released evaluation reports for several of these pilots. In addition, there are other methodology issues that have not been evaluated by the public, particularly with regard to this report's definition of low income household.[21]

IV. RECOMMENDATIONS AND BEST PRACTICES

The adoption of smart metering should be carefully examined and considered in light of the following key concerns and, where implemented, should be accompanied by several essential consumer protections. Our recommendations A through G below are accompanied by our proposed Best Practices for each recommendation.

A. Smart meter proposals must be cost-effective, and utilities must share the risks associated with the new technologies and the benefits used to justify the investment.

Smart metering investments are expensive. A rough estimate is that the new metering, communication, and meter data management systems will cost $200-$400 per meter.[22] The California PUC has authorized smart metering expenditures in excess of $5 billion for investor owned electric and gas utilities, all of which must be recovered from all customers as the meters are installed. Utilities seek compensation for this new investment and earn a rate of return through regulated rates for distribution or delivery service. In many cases, utilities have asked for a surcharge or other guaranteed recovery method so that utility shareholders will not bear any risks associated with the installation of the new metering and communication systems or the delivery of the future promised benefits. This distribution of risks is unfair to consumers.

Since any proposed smart metering investment must rely in part on estimates of projected future benefits, consumers bear a risk that the full value of the estimated benefits will not come to fruition. There are a variety of ways in which these risks can be properly allocated between consumers and utilities with traditional rate-making policies. For example, while the California PUC authorized a surcharge or tracker mechanism to recover smart metering costs, the Commission required the utilities implementing smart meters to credit the operational benefits as it estimated would occur with each meter that it puts into service. The Southern California Edison Co. is required to credit $1.42 of operational benefit per month beginning eight months after the meter is reflected in rate base.[23] Similar approaches have been adopted for PG&E and SDG&E's smart metering deployments. As a result, the utility's estimated operational costs are required to be booked as the meters are deployed and the risk that the operational benefits will not occur rests primarily with the utility.

Another approach has been implemented in Delaware in which the Public Service Commission has encouraged smart meter deployment, but will rely on traditional base rate cases in the future to evaluate both costs and benefits:

> The Commission approves the diffusion of the advanced metering technology into the electric and natural gas distribution system networks and the Commission permits Delmarva to establish a regulatory asset to cover recovery of and on the appropriate operating costs associated with the deployment of Advanced Metering Infrastructure and demand response equipment. The Commission, Staff, and other parties remain free to challenge the level or any other aspects of the asset's recovery in rates when Delmarva seeks recovery of the regulatory asset in base rates. For ratemaking purposes, the Commission may wish to consider an appropriately valued regulatory asset for advanced metering infrastructure investment consistent with the matching principle giving consideration to both costs and savings in the context of its next base rate case proceeding.[24]

More recently, the Maryland Public Service Commission issued an order on August 13, 2010 in response to Baltimore Gas & Electric's Application for Rehearing in which the Commission ruled that the proposed smart metering program could be implemented, but only if BGE accepted the decision to rely on the creation of a regulatory asset and the recovery of prudent costs in a future base rate case.[25]

As smart meters are deployed, it is recommended that regulatory commissions consider risk sharing rate recovery policies. Whatever the decision about cost recovery, the Commission must ensure that utility revenue enhancement opportunities stemming from advance metering (theft protection, less and shorter outages, more accurate meter read) be credited to consumers. This is a key point in that benefits ought to be netted against the costs and calculating the benefits becomes critical in order to maximize the potential netting or cost reduction to customers.

Sharing operational savings and benefits while certainly important, does not address the situation where the utility's estimate of future benefits relies heavily on projected generation supply prices and results from proposed demand response programs. The Maryland Public Service Commission correctly highlighted this concern in its first order rejecting BG&E's proposed smart meter investment because of the utility's reliance on the projection of the number of customers who will participate in new demand response programs, the degree of the change in their energy use, and the extent and long-term persistence of such changes, as well as the impact of these changes on the wholesale energy markets and resulting retail generation supply prices:

> If BGE's projected benefits are as conservative as BGE claims, we believe it is appropriate to require BGE to mitigate and more fairly allocate between the Company and its customers the risk that these benefits will not materialize as predicted. Any future BGE AMI proposal should include a mechanism by which it will do so.[26]

Our concerns relate as well to the situation in which the state regulatory commission has found that the smart metering proposal is cost effective, but is then faced with proposals to increase costs and pay for mistakes in the design of the system or the obsolescence of the chosen technology. There are growing concerns that the smart metering technology carries the risk of obsolescence due to the lack of final standards governing communications, interoperability, and the lack of policies governing the privacy rights of customers with respect to their detailed usage and pricing information. The National Institute for Standards and Technology (NIST) is developing recommended standards for interoperability and the protection of utility smart metering systems from cyber security risks, and the resulting recommendations must then be reviewed and adopted by FERC. However, since FERC does not regulate distribution utilities, these standards cannot be implemented unless accepted at the state level to govern smart metering installations. The costs associated with the future implementation of these standards is not yet known or reflected in many smart metering proposals currently pending in several states.

The premature adoption of the new metering and communication technologies has already resulted in stranded costs and significant increases in the budgets for these new systems in California. The California PUC approved PG&E's request to increase costs by almost $1 billion to change the communication system that was included in the original smart metering deployment application.[27] The same experience has occurred in Texas where Oncor Electric Delivery Co. installed smart meters that were later found not to comply with the resulting Texas PUC standards for these new metering systems. Nonetheless, Oncor's electricity customers were required to pay $93 million for the obsolete smart meters that were never installed and $686 million for meters with the newer technology.[28]

The new metering and communication systems should be planned to meet a robust set of future interoperability and privacy standards prior to their widespread installation rather than risking the potential of significant stranded costs that will be imposed on customers if the current controversies and lack of standards are not resolved promptly. At the very least, the risk of imprudent mistakes and failed designs should rest with the utility and its shareholders and not ratepayers.

We recommend the following Best Practices for the analysis of the costs and benefits of smart meters:

- A formal proceeding, including the opportunity for hearings with cross examination of witnesses, should be conducted to evaluate the statements in favor of the investment and the promised benefits with evidence that is subject to review and discovery by other parties.

All costs should be identified and the benefits should be calculated based on reasonable assumptions and actual experience.

- Utilities must bear some of the risk of less-than-predicted benefits or payback, whether cost recovery is authorized by means of a surcharge or in a traditional base rate case, so that customers are assured that the predicted savings actually occur.
- The proposed cost recovery method should be accompanied by an estimate of the impacts of the estimated costs on customer bills on a wide range of usage and demographic profiles (such as customers with lower than average usage and low-income customers participating in utility assistance programs).
- The proposed benefits should be accompanied by a risk analysis that identifies the potential scenarios that might impact the degree and persistence of any benefits that are projected. Utilities should bear the risk that their project design was faulty or that the chosen technologies fail to conform to pending national interoperability and cyber-security standards.
- The costs passed on to consumers must be subject to audit as part of each state's evidentiary hearing process.

B. Time-of-use or dynamic pricing must not be mandatory; consumers should be allowed to opt-in to additional dynamic pricing rate options.

Residential customers should be offered time differentiated rates on a strictly voluntary and opt-in basis. Utilities should design and offer a variety of rate options that have been evaluated and determined to be cost-effective and beneficial to customers with a wide range of usage profiles. The customer decision should rest on the customer's assessment of the value of being on a dynamic rate versus a traditional average rate. Utility estimates of future cost and energy savings from smart metering should not rest on mandatory time-based pricing, such as Time of Use (TOU) or Critical Peak Pricing (CPP). Instead, any alternative to the current fixed price structure should be voluntarily selected by the residential customer.

As is true in any implementation of a change in rate design, dramatic changes in the current pricing structure will create "winners" and "losers." Consumer groups are skeptical of relying on relatively small pilot programs of short duration composed of volunteers to suggest that mandatory time-based pricing programs will be appropriate for all or even most customers. Some residential customers prefer a more stable and fixed price for electricity. This may be particularly true for seniors and others on fixed income that need to carefully budget their use of electricity in order to pay the monthly bill on time and in full.[29] This is why national consumer organizations, such as AARP, the National Association of State Utility Consumer Advocates (NASUCA), and the National Consumer Law Center (NCLC) have adopted policies that oppose mandatory dynamic pricing. Finally, as described above, some consumers prefer programs that rely on carrots in the form of rebates or credits for allowing the utility to control key heating and cooling systems during critical peak periods and not sticks in the form of very high prices for electricity service during hot summer afternoons. Those most able to shift usage will sign up to an attractive, voluntary incentive program.

Most consumer advocates recognize the importance of reducing peak energy usage and the value that this resource has in the wholesale market structures that predominate in most states. However, as noted in Section III.B, supra, it is not necessary to rely entirely on TOU and CPP rate structures to achieve valuable results. Rather, these time-based rate structures should be made available on a voluntary basis to customers who would like them.

If a sufficient number of residential customers volunteer for dynamic rate options, the resulting value of such participation may be the most cost effective means of managing the overall portfolio and delivering the least cost electricity to all customers. Not all customers must participate in dynamic pricing programs to get system wide benefits. Furthermore, the voluntary approach will build support for the idea that customers who participate in such programs will benefit and the results will persist for a reasonable period of time, thus contributing to the social acceptance of such rate structures. Since additional study is needed concerning the long term persistence and impacts of dynamic pricing, an opt-in or voluntary approach is more likely to be valuable to determine longer term results and garner customer acceptance for such pricing programs in the future.

We recommend the following Best Practices concerning the implementation of dynamic pricing:

- Residential customers must not be required to accept a dynamic or time-based price structure for essential electricity service;
- Residential customers should be allowed to opt-in to dynamic or time-based pricing options.
- Consumers should be given easily understood tools to understand the trade-off between bill savings and price volatility for these rate options.

C. Regulators should assess alternatives to smart meters to reach the load management goals, particularly direct load control programs.

When considering an investment in smart metering to deliver demand response and conservation programs, regulators should compare the costs of the smart metering system with less expensive and well demonstrated direct load control programs. While acknowledging current savings through lower peak costs resulting from peak shavings, utility smart meter investments proposals often rely heavily on benefits associated with the future price of electric generation service to justify the significant costs. In other words, many smart meter proposals cannot be completely justified by relying on operational expense savings, such as the elimination of meter workers for reading and field work associated with connection and disconnection of service.[30]

Programs similar to the BG&E Peak Rewards program (which is a direct load control program using smart thermostats), can be implemented with current or upgraded communication systems and the installation of smart thermostats for those customers with central air conditioning systems that volunteer for the program in return for a credit or rebate. These programs do not require the installation of new metering systems. Many utilities have delayed any serious consideration of these less expensive and reliable systems and instead, have promoted the future installation of expensive smart metering systems that are accompanied by Critical Peak or Hourly Pricing.

Finally, the most cost-effective means to reducing usage overall is an investment in energy efficiency programs and less expensive improvements in billing options. A recent report issued by the American Council for an Energy-Efficient Economy (ACEEE) reviewed studies in the U.S. and Europe that have monitored customer reaction to exposure to more information about their electricity and natural gas usage, so-called "feedback" studies. [31] Many of these studies did not rely on new metering devices, but did involve the use of in-home devices and innovative billing systems. The ACEEE study concluded that the investments in more traditional energy efficiency programs are likely to have the most significant result in lowering consumption. The study acknowledged the potential benefits of linking the new metering systems to expose customers to "real time" energy usage information, but stated:

> While these insights are important, it is also important to recognize the substantially lower investment costs associated with enhanced billing programs (when compared to either real-time or real-time plus programs in particular due to their reliance on costly advanced metering equipment and in-home displays). These results suggest that enhanced billing strategies are currently one of the most effective and affordable means of providing residential consumers with meaningful feedback about their energy consumption patterns.[32]

The Department of Energy and other sources of stimulus funding have also recognized efficiency and weatherization programs as essential to reducing load growth, and our groups strongly support these programs. However, while energy efficiency lowers overall demand for electricity, it is not necessarily targeted towards reductions in peak demand. Thus, a combination of energy efficiency and peak demand programs should be considered.

We recommend the following Best Practices concerning the evaluation of smart metering proposals:

- Utilities should be required to evaluate the least cost means of achieving a reasonable level of peak load reduction and usage reduction overall in any smart metering proposal;
- Direct load control programs and energy efficiency and weatherization programs should be considered as potentially valuable alternatives to any smart metering proposals.

D. *Smart meter investments should not result in reduced levels of consumer protections, especially relating to the implementation of remote disconnection, and traditional billing and dispute rights should be retained.*

Smart metering proposals should not rely on any cost savings associated with the elimination of the premise visit to disconnect service for nonpayment for residential customers. The new metering systems come with a switch that allows the utility to remotely connect and disconnect the meter, thus eliminating the personnel and vehicle resources to provide these functions. Utility smart metering proposals typically include the benefits associated with eliminating these premise visits and field personnel resources as part of the value of the new metering systems. However, the fact that utilities can increase remote disconnections does not mean they should. For example, Pepco and Delmarva proposed a smart metering investment to the Maryland Public Service Commission in which a substantial savings equal to 18% of its total estimated operational benefits was identified for the remote turn on and turn off function of the new meters. Consumers support the use of this metering function to connect electricity service and to disconnect service when the dwelling or rental unit is empty and the purpose is to prevent the use of electricity between the old customer and the application of the new customer. However, consumer groups oppose the use of this function to disconnect service to residential customers for nonpayment of service without a health and safety visit to the premises where that is required by state regulators. Other protocols and customer protections need to be developed to account for this new technology.

Electricity is vital to a residential household's health and safety. The household without electricity lacks lights, running water (if the house requires a pump to provide water), refrigeration, cooling fans and air conditioners, and, during the winter period, most heating sources. Even if the household heats with natural gas or propane heaters, they cannot operate without electricity. It is common for a household that is denied electricity to turn to alternative and often dangerous means of providing light and heat in the home. These alternatives are dangerous because candles can result in house fires, alternative generators or heat sources can result in death due to carbon monoxide poisoning, and lack of proper heat in the home can result in death due to hypothermia.

While there is no national compilation of deaths due to the use of unsafe methods of providing lighting and heating in a disconnected dwelling, there are instances reported every year of the deaths of children and adults due to the use of a candle in a dwelling without electricity or heat.[33] Therefore, every state regulatory commission regulates the disconnection of service very carefully and consumer protection regulations typically require multiple notices and attempts to contact the customer to avoid disconnection where possible. These policies should be maintained and enhanced.

Remote disconnection of service carries significant implications for customer protections. Such an inexpensive means to disconnect service is likely to have the unintended consequence of incenting the utility to rely on disconnection as opposed to potentially more expensive efforts to contact the customer and resolve the nonpayment and avoid the disconnection. The use of the remote disconnection feature means that the utility have the ability to disconnect service much faster and in a greater frequency unless additional consumer protections are deployed. There is clearly a concern that relying on the remote disconnection functionality of smart meters could increase the volume of disconnections. According to a study issued by the California

Division of Ratepayer Advocate, the rate of disconnection of residential customers increased in PG&E's service territory once the remote disconnection switch was used with the new metering system. The increase in smart meter shutoffs appears to be disproportionately large compared to shut-offs of homes with traditional meters that require a premise visit. There are now three times more smart meters installed, but smart meter disconnections have increased 12-fold in one year.[34]

Furthermore, it is important to ensure that the use of this feature does not eliminate the standard practice in many states of an attempt to contact the customer at the time of disconnection.[35] A utility's premise visit to the customer's dwelling at the time of disconnection which is required in some states is for the purpose of allowing the utility to respond to customer statements at the time of disconnection, detect a medical emergency, or other conditions that may result in forbearance by the utility from effectuating the disconnection of service, and consider the customer's dispute allegations if made orally at that time. Where an attempt at personal contact is required, some utilities accept customer payment by means of a credit or debit card. Where site visits are not required, consumer protections may require new safeguards in addition to attempts to contact the customer through telephone or electronic mail may be required, such as the newly adopted requirement of the California PUC that mandates that utilities with smart meters must conduct a premise visit to protect certain vulnerable customers prior to disconnection of service.[36] A recent decision of the New York Public Service Commission explicitly provided that current consumer protections relating to disconnection would be retained in the event that smart metering was implemented, thus preventing New York utilities from relying in any savings associated with remote disconnection of service.[37]

Consumer advocates are also concerned about the potential for widespread implementation of pre-paid electric service with the onset of smart metering. This option has been typically marketed to low income customers and could result in an increase in disconnections of service without any regulatory process to obtain contact and avoid disconnection or make a payment plan, rights that are available to other customers.

Finally, the deployment of smart meters should not result in an abandonment of traditional consumer protections associated with billing accuracy, the timeliness of bill issuance, and the customer's right to dispute a bill or a utility's conduct with the utility and then with the state regulatory commission. There is some anecdotal evidence from California and Texas where smart metering is being deployed that attempts by customers to dispute the accuracy of the bill, the meter, or the issuance of estimated bills when the new smart meters do not communicate properly with the utility's communication network, are treated improperly by the utility as questioning the accuracy of the meter itself.

We recommend the following Best Practices with respect to consumer protections that should accompany the implementation of smart metering:

- Federal policymakers should recognize the health and welfare implications of the use of remote disconnection of service;

- State regulators should be encouraged to require that existing consumer protections be retained or enhanced, particularly with respect to the implementation of remote disconnection and pre-paid electric service options; and,
- Traditional state utility consumer protection regulations governing the issuance of bills and the dispute rights of customers should not be ignored or minimized with the installation of smart meters and consideration should be given to strengthening consumer protections before a disconnection can occur.

E Privacy and cyber-security concerns should be addressed prior to a smart meter rollout.

Another consumer protection policy that is receiving more attention lately relates to the utility's use of the individual household detailed usage information that accompanies the installation of smart meters. This information can inform those with access to this data whether any person is home, the daily household usage pattern, and even whether certain appliances are being used at certain times of the day. Some states that are considering or have approved smart metering deployment have not yet developed or enacted policies to govern the ability of third parties to get access to this information for marketing purposes or make use of Smart Grid technologies.[38] Consumer groups typically propose that utilities not be allowed to transmit the customer's household usage and billing information to any third party without the affirmative consent of the customer. When given, such approval should not allow the third party to use this information for any other purpose than that approved by the customer.

Closely linked to the privacy issue is the consumer concern about the security of the household usage information and the Smart Grid itself in the face of widespread threats to cyber security that are reported almost daily. National Institute of Standards and Technology (NIST) is developing standards to assure cyber security, but no computerized database is safe from a determined hacker. This is particularly the case when thousands of utilities will be operating their own systems, each of which will require a level of monitoring and protection that will be difficult to assure on a uniform basis. The conversion of the current utility systems from analog technologies to digital technologies carries with it significant risks of inappropriate access and potentially dangerous and criminal actions that could threaten a utility's distribution and transmission operations, as well as raise the potential of unauthorized access to customer household usage information. While utilities typically assure regulators and policymakers that their new Smart Grid systems will meet all required standards, more work is needed to examine the resources, skills, and investments necessary to actually implement those standards, monitor systems, and spot potentially dangerous intrusions and attempts to infiltrate the utility's data systems through these new meters. At least one organization in California has publicly claimed that it has already hacked a utility's smart meter system.[39]

We recommend the following Best Practices with respect to privacy and cyber-security implications of smart meters:

- Utilities should complete security plans and standards and upgrade necessary communications prior to or at the same time as the installation of smart meter.

F. *Utilities and other policymakers should include comprehensive consumer education and bill protection programs in any evaluation or implementation of smart meter proposals.*

Utilities should be required to develop and include the costs of a significant outreach and education program as part of any smart metering and pricing application. We recommend such education go beyond the typical bill insert and promotional advertising that most utilities rely upon to communicate with their customers. The consumer education program should be comprehensive and emphasize the installation process for new metering, the programs that will be implemented as a result of the new metering technologies, and the bill impacts associated with the costs and benefits of the approved program. If the California roll-out of smart metering is any indication, customer education about the metering installation process and the basis for the value of the increased customer bills to pay for the new metering systems must be communicated through a wide variety of mediums. The expenses associated with a proper consumer education plan are likely to be substantial and should be identified and included as part of the costs of the implementation of smart metering in the utility's business case, not merely mentioned as an afterthought. Utilities should be required to work closely with state advocates, commissions, municipalities and community based organizations in the design and implementation of their consumer education plans. While no evaluation of the individual California utility outreach and education programs is available, anecdotal evidence suggests that the customer reaction to smart metering deployment in the form of customer and public official complaints differs widely among those utilities and should perhaps be studied more closely.

As part of its consumer education program and the implementation of alternative pricing programs, utilities should offer bill protection and other programs to assure customers that the new meters are working properly. For example, utilities should offer to compare usage and bill calculations under the old and new meters for a trial period. In addition, utilities should offer customers who voluntarily agree to participate in a direct load control program or a dynamic pricing program a guarantee that the customer will save on their bill and allow customers to opt out without penalty if such savings do not materialize.

Finally, we agree with the Maryland Public Service Commission that performance metrics should be developed to measure the actual results of any smart metering and new pricing education plan.[40]

We recommend the following Best Practices with respect to consumer education and monitoring the deployment of smart meters:

- Utilities should be required to develop a comprehensive customer outreach and communication program as part of any proposed deployment of smart meters;
- Customer education programs should be developed with state advocates, commissions, municipalities and local consumer and community organizations;
- An approved smart metering and pricing education plan should include

performance metrics to ensure that the plan is effective and has the results intended; and

- Customers should be offered bill protection programs associated with any voluntary dynamic pricing program.

G. *Investments in smart meters and other Smart Grid proposals need to be verifiable and transparent and the utilities need to be held accountable for the costs they want customer to pay and the benefits they promise to deliver. Costs should be reasonable and prudent.*

As stated earlier, any smart metering and Smart Grid proposal should be supported by a robust benefit-cost analysis in the utility business case. Moreover, any application for cost recovery for smart metering and Smart Grid program filing must include detailed design requirements, performance goals, metrics, and milestones, all costs and quantified benefits. At the end of pilot smart metering or Smart Grid programs, the utility company should be required by its commission to prepare a summary report outlining deployment progress versus milestones, system performance levels and customer benefits versus the plan. This report should be filed with the Commission and subject to comment from interested stakeholders as part of the evidentiary hearing. The report should also address deployment lessons learned and the desirability of continuing the metering or Smart Grid program. All Smart Grid costs should be subject to such other prudency reviews and audits as deemed necessary and appropriate by state utility commissions as part of their evidentiary hearing process.

We recommend the following Best Practices with respect to regulatory oversight of smart metering and Smart Grid investments:

- Proposed investments in smart metering and Smart Grid technologies should be justified by a robust cost-benefit analysis;
- The implementation of smart metering and Smart Grid investments should be accompanied by measurable and enforceable performance metrics; and
- Smart metering and Smart Grid investments must be subject to prudency reviews and audits to determine if the consumer benefits have been delivered as promised.

V. CONCLUSION

Smart metering technologies may deliver important benefits to utility customers that can help to mitigate higher electricity prices that will result from initiatives to invest in renewable energy resources and reduce greenhouse gas emissions. However, it is not evident that in all cases, utilities' current implementation of the Smart Grid is occurring in a manner that is appropriately targeted. Nor, is it clear that utility customers, particularly vulnerable households, will see these benefits or experience bill reductions to offset the costs of the smart metering systems. This paper is designed to inform policymakers on consumer concerns and sets forth recommended "Recommendations and Best Practices" to reduce the risks of adverse consequences from the adoption of smart meters in the pursuit of the legitimate objectives of Smart Grid policies.

END NOTES

1. At least one public utility regulator has stated that ''There is no point in having smart meters if you're still going to have dumb rates.'' Richard Morgan, Commissioner, District of Columbia Public Service Commission, Rethinking 'Dumb' Rates, Pub. Util. Fortnightly, Mar. 2009.
2. It should be noted that municipal and publicly owned electric utilities are typically not regulated directly by state public utility commissions, but undertake investments and set rates pursuant to the direction of their members.
3. This paper makes frequent references to recent dynamic pricing pilots conducted by the California electric utilities in 2002-2004 (Statewide Pricing Pilot), Baltimore Gas & Electric's Smart Pricing Pilot conducted in 2008, Connecticut Light & Power's Plan-It-Wise Energy Pilot conducted in 2008, and the District of Columbia PowerCents pilot program conducted in 2007-2008.
4. Ahmad Faruqui and Sanem Sergici, *Household Response to Dynamic Pricing of Electricity –A Survey of the Experimental Evidence*, (January 10, 2009), *available at* http://www.hks.harvard.edu/hepg/
5. Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot: Final Report* at 75(March 16, 2005). The results of the California Statewide Pilot Program were summarized in Ahmad Faruqui & Sanem Sergici, *Household Response to Dynamic Pricing of Electricity –A Survey of the Experimental Evidence* (January 10, 2009), *available at* http://www.hks.harvard.edu/hepg/
6. Maryland Public Service Commission, In the Matter of the Application of Baltimore Gas & Electric Co. for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for Recovery of Costs, Case No. 9208, Order 83410 (June 21, 2010) at 47-48.
7. BG&E's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation (April 28, 2009).
8. Customers enrolled in the Critical Peak Pricing program in this California pilot program did reduce peak usage during critical peak events, but no change in overall annual usage occurred. Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot: Final Report* (March 16, 2005).
9. "Results of the CL&P Plan-It Wise Energy Pilot" as provided to the Connecticut Department of Public Utility Control for an overview of the results of the CL&P pilot. This document and accompanying appendices are available at: http://www.cl-p.com/Home/SaveEnergy/GoingGreen/PlanitWise.aspx
10. D. Memtzow, D. Delurey and C. King, "The Green Effect," Public Utility Fortnightly (March 2007).
11. A broad range of cost-saving energy efficiency and demand reduction measures that do not require smart meters have been shown to produce consumption and peak demand reductions. Consumer groups strongly support such programs provided they are cost-effective, measurable, and verifiable.
12. BG&E's Peak Rewards program provides participating residential customers with a bill credit up to $100 each summer, depending on the level of participation selected by the customer, *i.e.*, the level of control allowed on the customer's thermostat. For further details on this program, see: http://peakrewards.bgesmartenergy.com/what-is-peakrewards
13. *See Final Report of the Maryland PSC to the Maryland Legislature, Options for Re-Regulation and New Generation* at 6, 23 (December 10, 2008), *available at* http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm .
14. Klinenberg, Eric, Heat Wave: A Social Autopsy of Disaster in Chicago, University of Chicago Press (2002).
15. Centers for Disease Control and Prevention/Morbidity and Mortality Weekly Report, July 28, 2006 / 55(29);796-798 < http://www.cdc.gov/mmwr/preview/mmwrhtml/mm5529a2.htm>
16. Snyder, Lynne and Baker, Christopher, Affordable Home Energy and Health: Making the Connections, AARP Public Policy Institute, #2010-05 (June 2010), Executive Summary at 1; available at www.aarp.org/ppi
17. See, e.g., Alexander, Barbara, Smart Meters, Real-time Pricing, and Demand Response

Programs: Implications for Low Income Electric Customers (May 2008), available at: http://www.pulp.tc/Smart_Meter_Paper_B_Alexander_May_30_2007.pdf); Brockway, Nancy, Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers, NRRI 08-03 (February 13, 2008), available at: www.nrri.org

18. The U.S. Energy Information Administration (U.S. Department of Energy) has released summary tables of information derived from the 2005 Residential Energy Consumption Survey (RECS). Table US8, Average Consumption by Fuels Used, 2005 presents average usage by fuel type and household income status. Families with income below 100% of federal poverty use an average of 9,038 kwh/year, those with income between 100% and 150% of poverty use 10,342 kwh/year, but households with income above 150% of poverty use 12,158 kwh/year. The same pattern exists for natural gas usage.
19. Using data from the most (RECS), households living at or below 150% of the federal poverty level are 45% more likely than households living above 150% of the poverty level to use heating equipment that is greater than 20 years old. Similarly, these low-income households are 19% more likely to use a refrigerator that is 20 years old or more, 73% more likely to use a central air-conditioning system more than 20 years old, and 142% more likely to use a water heater more than 20 years old.
20. Nevertheless, it needs to be acknowledged that many low-income customers have taken advantage of the Home Weatherization Assistance Program, ARRA funding and state and local utility programs to weatherize their homes, thereby providing a valuable service to these customers by consequentially reducing their energy consumption.
21. See. e.g., The Impact of Dynamic Pricing on Low Income Customers," Institute for Energy Efficiency (June 2010). This report was authored by several consultants with The Brattle Group. This report is available at: http://www.electric-efficiency.com/reports/index.htm The IEE is a sister organization to the Edison Electric Institute.
22. Plexus Research, Inc., Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005, Prepared for Edison Electric Institute, September 2006, at xii. Plexus Research, Inc. developed an estimate for Edison Electric Institute (EEI) of the cost of various parts of an AMI implementation, pegging the per meter cost at between $200 and $525, depending on the functionality included.
23. California PUC Decision No. 08-09-039 (September 18, 2008). It should be noted that the California utilities submitted a business case for smart metering that included over 80% of the benefits in the form of reduced operational costs.
24. The Delaware Commission has not approved Delmarva's smart meter proposal for the purposes of rate recovery. Rather, the Commission specifically stated that Delmarva would have to come before the Commission in a future base rate case and justify its investment in order to obtain rate recovery. In its Order No. 7420 issued on September 16, 2008, the Commission states that it "should encourage Delaware's energy companies to continue moving forward with its investment in advanced metering technology" but deferred any analysis of costs and benefits and cost recovery except in the context of a base rate case proceeding. Order No. 7420, September 16, 2008, PSC Docket No. 07-28 and PSC Regulation Docket No. 59. Order at 5-6.
25. Maryland Public Service Commission, In the Matter of the Application of Baltimore Gas & Electric Co. for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for Recovery of Costs, Case No. 9208, Order No. 83531 (August 13, 2010).
26. Maryland Public Service Commission, In the Matter of the Application of Baltimore Gas & Electric Co. for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for Recovery of Costs, Case No. 9208, Order 83410 (June 21, 2010) at 47, 53.
27. In fact, the actual experience associated with the implementation of smart metering and the associated communication systems in California reflect higher costs and delayed installation. For example, Pacific Gas & Electric halted its AMI deployment in order to make a change in its communication system and metering functionality.

The utility subsequently sought and obtained approval from the California PUC to increase its AMI costs by over $900 million on a present value basis, thus bringing the total cost estimate to roughly $3.2 billion. Docket #: A.07-12-009 See California PUC News Release issued March 12, 2009, available at: http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/98459.htm

28. According to an August 3, 2009 article in the Dallas Morning News, "Consumers are already paying $2.21 a month for the new round of meters, as retail electricity companies pass along Oncor's charge to their customers. That cost will last 11 years. If commissioners decide consumers must pay for the first smart meters,that could add about $1.70 a month to the average customer's bill, according to calculations by the Steering Committee of Oncor Cities." See, http://www.dallasnews.com/sharedcontent/dws/dn/latestnews/stories/DN-oncor_03bus.ART.State.Edition1.3cf2fb0.html The Texas PUC issued an order allowing such cost recovery in Application of Oncor Electric Delivery Co. LLC for Authority to Change Rates, PUC Docket No. 35717, August 31, 2009.
29. There is historical evidence to support the conclusion that residential customers typically prefer flat or stable rate structures for essential electricity service over traditionally poorly designed time differentiated rate designs. Time of Use rates have been available to customers for many years; however, they have been unpopular with the majority of residential customers, as reflected in the very small percentage of residential customers who opt for this rate option in most states.
    - Maine actually implemented a mandatory TOU rate structure for high use electric customers in the early 1980's, aiming to send "proper price signals" to residential customers with electric heat (Central Maine Power Company was a winter peaking utility at that time). This mandatory TOU rate structure worked in an acceptable fashion, albeit with controversy from some customers, for many years, but when electricity prices began to significantly increase in the early 1990's, the TOU rate structure was changed as well to reflect the growing cost of electricity during peak hours and the expensive new generation contracts that were flowing through the rate structure. Customer reaction was swift and vociferous, particularly from elderly customers who were living in apartments and homes in which electric baseboard heat had been installed under the previous regime of lower priced electricity. The previously promised potential to lower their electricity bill by relying on TOU rates had vanished and such customers were faced with significantly higher bills in order to heat their homes during peak usage hours when they were home during the day. Within several years the TOU rate structure became voluntary.
    - TOU rates have been available to BGE's residential customers in Maryland for years, but only 6% of the residential class has selected to remain on this rate option. The same is true in most other states.
    - Puget Sound Energy in Washington implemented a mandatory Time of Use program for residential customers in 2001 that was originally intended to allow customers to reduce the electric bill by shifting usage to off peak periods when prices were less expensive. However, the program did not result in customer savings and, in many cases, resulted in higher monthly bills under the TOU rate structure. By late 2002, the program was halted by the utility and with the approval of the Washington regulators.
    - In response to an earlier effort to mandate Time of Use rates for residential customers in New York, the New York Legislature has prohibited time-based rates for residential customers except upon affirmative and voluntary selection.
30. The consumer groups note that the major source of any claimed operational benefits associated with smart metering proposals relies on the elimination of entry-level jobs associated with meter reading and field operations., Job training should be made available for these employees to assist them in getting productive jobs at the utility or elsewhere.
31. Ehrhardt-Martinez, et al., "Advanced Metering Initiatives and Residential Feedback Programs:

A Meta-Review for Household Electricity-Saving Opportunities," ACEEE, Report No. E105 (June 2010). Available at: www.aceee.org

32. Ibid., at iv.
33. Marty Ahrens, *Home Candle Fires*, National Fire Protection Association (June 2010)(particular risk of fatalities where candles used in absence of electricity) Exec Summary at ii.

    In early 2008 at the request of a Philadelphia newspaper, the Pennsylvania Public Utility Commission's Bureau of Consumer Services provided its internal compilation of media-reported deaths related to utility terminations across the state. This list documents 71 adult and child deaths since 1989, most related to impact of fires starting in households without electricity or heat or both. These tragic events are not limited to Pennsylvania.

    - The tragic 2006 death of six Chicago children in an apartment without electricity, where candles apparently had been used for months, illustrates a horrific example of the dangers associated with disconnection of essential electric service.
    - Fire officials said a fire that killed a woman and a 7-year-old girl early Saturday in east Baltimore was started by candles. The fire happened shortly before 2 a.m. in the 1400 block of North Broadway Street. Investigators said the occupants of the home didn't have electricity. A third person attempting to escape the fire is being treated at Shock Trauma, officials said. Fire investigators said candles started the fire. … No one at the address applied for energy assistance through the city. So far this year, 11 fire deaths have been reported in Baltimore, three of which have been in homes without electric. Two weeks ago, a woman died at a fire in her home that was caused by candles. Officials said she didn't have electric and no one at the home sought energy help. — *WBAL-TV* and *Baltimore Sun*, April 19-20, 2009 See: http://www.wbaltv.com/news/19233387/detail.html and http://www.baltimoresun.com/news/local/bal-md.regiondigest190apr19,0,3582882.story
    - An August, 2006 fire in a candle-lit Rochester, New York home without electricity: Candles left burning caused an overnight fire. It was not an act of carelessness on the part of the homeowner, but one of necessity. [The homeowner] was laid off, and unable to keep up with bills. She spent the summer without electricity.
    - The 2005 death of a New York City child in a fire started by a candle while power was shut off. It was reported that the customer had made payment arrangements sufficient to be reconnected, the reconnection was scheduled for the next day, but the fire occurred during the intervening night:

      "[A] Con Ed spokesman ... confirmed electricity to the apartment had been cut off at 1:45 p.m. Monday. Two hours later, [the customer] appeared at a local Con Ed branch to pay $700 - almost half the outstanding bill. [A]n order to restore electricity within 24 hours was issued two hours later. Tragically, it was not in time - firefighters responded to the scene of the fatal fire at 10:45 p.m."
    - In a 2003 Syracuse, N.Y. incident, "A Syracuse mother and her three children, who have been using candles to light their home since the power was shut off earlier this month, escaped unharmed when a candle ignited a blaze in a second-floor bedroom Friday morning.... [A] NiMo spokesman said the company disconnects the power when a customer is unresponsive to letters, calls and offers of payment agreements. He said company officials had a phone conversation with the customer Thursday to discuss the bill.
34. Division of Ratepayer Advocate, Status of Energy Utility Service Disconnections in California (November 2009), available at: http://www.dra.ca.gov/NR/rdonlyres/2A0C5457-56FC-4821-8C4D-457F4CF204D1/0/20091119_DRAdisconnectionstatusreport.pdf
35. While there is no readily available national compilation of the state regulations, our organizations are familiar with the regulations in New York, Maryland, Ohio, and Illinois as examples of state utility consumer protection regulations that require the utility to attempt contact at the customer's premises prior to physical disconnection of service.

36. California PUC, Interim Decision Implementing Methods to Decrease the Number of Gas and Electric Utility Service Disconnections, Docket No. R. 10-02-005 (July 29, 2010).
37. The New York Commission stated, "Finally, we remind the companies that termination of service for nonpayment is subject to Home Energy Fair Practices Act (HEFPA) regardless of whether that disconnection is performed by physical (on site) or electronic (remote) service shut off. No utility may utilize AMI for remote disconnection of service for nonpayment unless it has taken all of the prerequisite steps required by HEFPA, including the requirement of 16 NYCRR §11.4(a)(7) that customers must be afforded the opportunity to make payment to utility personnel at the time of termination. This process requires a site visit, even where a remote device is utilized." See Order Requiring Filing of Supplemental Plan, Case Nos. 94-E-0952, 00-E-0165, and 02-M-0454 (December 17, 2007).
38. The California PUC has stated that it will address these issues in separate workshops and orders subsequent to its recent Smart Grid Deployment Plan rulings. The comments submitted to date on the customer privacy and access to usage data issues reflect a wide range of interests. See, Decision 10-06-047, Decision Adopting Requirements For Smart Grid Deployment Plans Pursuant To Senate Bill 17 (Padilla), Chapter 327, Statutes Of 2009, Docket No. R-08-12-009 (June 28, 2010).
39. "Smart Grid, Cyber Security, and "Perfect Citizen," Intelligent Utility http://www.intelligentutility.com/article/10/07/smart-grid-cyber-security-and-perfect-citizen
40. Maryland Public Service Commission, In the Matter of the Application of Baltimore Gas & Electric Co. for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for Recovery of Costs, Case No. 9208, Order No. 83531 (August 13, 2010).

ATTACHMENT KLO-3

OUCC
IURC Cause No. 44963
Data Request Set No. 6
Received: September 25, 2017

OUCC 6.1

Request:

In Indiana, where deployment is complete or in progress, what percentage of customers are in the “on hold” category (where deployment was attempted but unsuccessful)? Please provide the raw numbers used to calculate the percentage.

Response:

As of September 26, 2017, Duke Energy Indiana had 0.19% of customers in on-hold status in areas where deployment was complete or in progress. That percentage is based upon 529 customers in on-hold status out of 274,845 AMI meters deployed.

ATTACHMENT KLO-4

OUCC
IURC Cause No. 44963
Data Request Set No. 2
Received: August 30, 2017

OUCC 2.1

Request:

In response to OUCC DR 1.13, DEI responded that the amount of meter reading expense included in base rates for residential and small commercial service is approximately $0.54 per month. Please provide the detailed calculation to support this amount of expense, including the assumed number of customers, by customer class, and the total annual amount of meter reading expense, by account, that was included in the revenue requirement approved in Cause No. 42359.

Response:

Please see Attachment OUCC 2.1-A for information on meter reading expense, by class of customers, embedded in rates based upon final rates in Cause No. 42359. The amount of monthly meter reading expense can be derived by the following formula:

Meter Reading Expense *1000 / Number of All Other Meters / 12

Witness: Jeff Bailey

PSI ENERGY, INC.

RETAIL COST OF SERVICE STUDY

ALLOCATION OF OPERATION & MAINTENANCE EXPENSES
TO RATE GROUPS AND CLASSES OF SERVICE
TOTAL CUSTOMER ACCOUNTS EXP (CONNECTION RELATED)
(DOLLARS IN THOUSANDS)

CLASS OF SERVICE	SPECIFIC PROPERTY CODE	RATE CODE	NUMBER OF ELECTRONIC LOAD PROFILE METERS	BILLING EXPENSE	LPS NUMBER OF INDICATING DEMAND MTRS.	BILLING EXPENSE	CIS NUMBER OF INDICATING DEMAND MTRS.	BILLING EXPENSE	NUMBER OF ALL OTHER METERS	BILLING EXPENSE	TOTAL METER READING EXPENSE
SECONDARY SERVICE											
RESIDENTIAL AND FARM SERVICE											
RATE RS											
SINGLE PHASE		RFXY060-1,FY070-1	0	$0	0	$0	0	$0	604,460	$3,943	$3,943
RS-OPTIONAL HIGH EFFICIENCY		RFXY080-1	0	0	0	0	0	0	34,211	223	223
TOTAL RATE RS			**0**	**0**	**0**	**0**	**0**	**0**	**638,671**	**4,166**	**4,166**
COMMERCIAL AND INDUSTRIAL											
RATES CS AND FOC											
COMMERCIAL AND FIBER OPTIC CABLE (FOC)		C 110,490	0	0	0	0	0	0	60,789	397	397
SPACE HEATING		K 110,113,115,116	0	0	0	0	0	0	3,334	22	22
FIRE SIRENS		A 120	0	0	0	0	0	0	0	0	0
METERED CATV		C 130	0	0	0	0	0	0	3,422	22	22
OPTIONAL HIGH EFFICIENCY		K 145, 146	0	0	0	0	0	0	62	0	0
TOTAL RATE CS AND FOC			**0**	**0**	**0**	**0**	**0**	**0**	**67,607**	**441**	**441**
RATE LLF											
METERED SECONDARY		150, 151, 155	208	71	872	48	18,941	1,050	0	0	1,169
METERED SECONDARY - TOU (A)	(8-0)	152, 153, 154	3	1	0	0	0	0	0	0	1
METERED SECONDARY - RTP (AB)	(9-0)	150	11	4	0	0	0	0	0	0	4
METERED PRIMARY		150, 151, 155	19	6	42	2	6	0	0	0	8
METERED PRIMARY -RTP (AE)	(9-0)	150	1	0	0	0	0	0	0	0	0
OPT. HIGH EFFICIENCY-METERED SECONDARY		K 135, 136	69	24	61	3	141	8	0	0	35
RATE HLF											
METERED SECONDARY		453	483	174	3,552	199	0	0	0	0	373
METERED SECONDARY - TOU (B)	(8-0)	449	4	1	0	0	0	0	0	0	1
METERED SECONDARY - RTP (S)	(9-0)	453	16	5	0	0	0	0	0	0	5
METERED PRIMARY - RTP (T)	(9-0)	453	3	1	0	0	0	0	0	0	1
METERED PRIMARY		453	61	21	8	0	0	0	0	0	21
METERED PRIMARY		453	0	0	0	0	0	0	0	0	0
SPECIAL CONTRACT											
METERED SECONDARY		150	0	0	0	0	0	0	0	0	0
METERED SECONDARY - (AF)	(6-0)	I 524	0	0	0	0	0	0	0	0	0
TOTAL COMMERCIAL AND INDUSTRIAL			**878**	**308**	**4,535**	**252**	**19,088**	**1,058**	**67,607**	**441**	**2,059**
OTHER SALES											
RATE OL - OUTDOOR LIGHTING		327	0	0	0	0	0	0	0	0	0
RATE WHOL - OUTDOOR LIGHTING - WEST HARRISON		327 (328)	0	0	0	0	0	0	0	0	0
RATE WHNSP - OUTDOOR LIGHT - NON-STANDARD-WEST HARRISON		327 (482)	0	0	0	0	0	0	0	0	0
RATE WP - WATER PUMPING		I 304	0	0	0	0	0	0	1,500	10	10
RATE FC - FLOOD CONTROL PUMPING		A 330	0	0	0	0	0	0	39	0	0
RATE AL - AREA LIGHTING		480,481	0	0	0	0	0	0	0	0	0
RATE DLR - DECORATIVE LIGHTING		A 492	0	0	0	0	0	0	0	0	0
STREET LIGHTS											

PSI ENERGY, INC.

RETAIL COST OF SERVICE STUDY

ALLOCATION OF OPERATION & MAINTENANCE EXPENSES
TO RATE GROUPS AND CLASSES OF SERVICE
TOTAL CUSTOMER ACCOUNTS EXP (CONNECTION RELATED)
(DOLLARS IN THOUSANDS)

	A	B	C	D	E	F	G	H	I	J	K	Z
16	**CLASS OF SERVICE**	**SPECIFIC PROPERTY CODE**	**RATE CODE**	**NUMBER OF ELECTRONIC LOAD PROFILE METERS**	**BILLING EXPENSE**	**LPS NUMBER OF INDICATING DEMAND MTRS.**	**BILLING EXPENSE**	**CIS NUMBER OF INDICATING DEMAND MTRS.**	**BILLING EXPENSE**	**NUMBER OF ALL OTHER METERS**	**BILLING EXPENSE**	**TOTAL METER READING EXPENSE**
17												
65	RATE HLS - ST. OWNED - CO. MAINTAINED		P 355	0	0	0	0	0	0	0	0	0
66	RATE HLS - ST. OWNED - ST. MAINTAINED		P 356	0	0	0	0	0	0	0	0	0
67	RATE MHLS - ST. OWNED - ST. MAINTAINED METERED SERV.		P 357	0	0	0	0	0	0	279	2	2
68	TOTAL RATE HLS AND MHLS			**0**	**0**	**0**	**0**	**0**	**0**	**279**	**2**	**2**
69												
70	RATE HL - CO. OWNED - CO. MAINTAINED		P 387	0	0	0	0	0	0	0	0	0
71												
72	RATE SL - COMPANY OWNED		P 469,470,472,473	0	0	0	0	0	0	0	0	0
73	RATE SL - CUSTOMER OWNED		P 476	0	0	0	0	0	0	0	0	0
74	TOTAL RATE SL - PSI			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
75												
76	RATE WHSL - WEST HARRISON		P 477	0	0	0	0	0	0	0	0	0
77												
78	SPECIAL CONTRACTS											
79	RATE UOLS - COMPANY OWNED		324	0	0	0	0	0	0	0	0	0
80	RATE UOLS - CUSTOMER OWNED		323	0	0	0	0	0	0	0	0	0
81	RATE MOLS - COMPANY OWNED		326	0	0	0	0	0	0	0	0	0
82	RATE MOLS - CUSTOMER OWNED		325	0	0	0	0	0	0	4	0	0
83	TOTAL RATES UOLS AND MOLS			**0**	**0**	**0**	**0**	**0**	**0**	**4**	**0**	**0**
84												
85	MISCELLANEOUS CONTRACTS											
86	RATE TS - TRAFFIC SIGNAL		P 180	0	0	0	0	0	0	0	0	0
87	RATE WHTL - TRAFFIC SIGNAL - WEST HARRISON		P 181	0	0	0	0	0	0	0	0	0
88	RATE MS - METERED TRAFFIC AND FLASHER SIGNAL		C,K,I,T,P 182	0	0	0	0	0	0	33	0	0
89	RATE FS - FLASHER SIGNAL		P 193	0	0	0	0	0	0	0	0	0
90	**TOTAL OTHER SALES, STREET LIGHTS,**											0
91	**AND MISCELLANEOUS CONTRACTS**			**0**	**0**	**0**	**0**	**0**	**0**	**1,855**	**12**	**12**
92	**TOTAL - SECONDARY SERVICE**			**878**	**308**	**4,535**	**252**	**19,088**	**1,058**	**708,133**	**4,619**	**6,237**
93												
94	**PRIMARY SERVICE**											
95	PRIMARY SERVICE FROM THE COMMON SYSTEM											
96	RATE LLF											
97	METERED SECONDARY		157	4	1	0	0	0	0	0	0	1
98	METERED PRIMARY		157	48	16	3	0	0	0	0	0	16
99	METERED PRIMARY	(4)	148	6	2	0	0	0	0	0	0	2
100	METERED PRIMARY (BILLED SECONDARY)	(6-0)	150	6	2	0	0	0	0	0	0	2
101	METERED PRIMARY (BILLED SECONDARY)	(6-4)	150	2	1	0	0	0	0	0	0	1
102	METERED PRIMARY - RTP (AC) (BILLED SEC)	(9-6)	150	1	0	0	0	0	0	0	0	0
103												
104	RATE HLF											
105	METERED SECONDARY		454	2	1	0	0	0	0	0	0	1
106	METERED PRIMARY		454	125	43	0	0	0	0	0	0	43
107	METERED PRIMARY	(3)	454	1	0	0	0	0	0	0	0	0
108	METERED PRIMARY	(4)	458	16	5	0	0	0	0	0	0	5
109	METERED PRIMARY	(6-4)	458	0	0	0	0	0	0	0	0	0
110	METERED PRIMARY - TOU (F)	(8-0)	450	1	0	0	0	0	0	0	0	0
111	METERED PRIMARY - TOU (G)	(8-4)	459	2	1	0	0	0	0	0	0	1
112	METERED PRIMARY - RTP (H)	(9-0)	I 454	15	5	0	0	0	0	0	0	5
113	METERED PRIMARY - RTP (I) & (E)	(9-4)	I 458	5	2	0	0	0	0	0	0	2

PSI ENERGY, INC.

RETAIL COST OF SERVICE STUDY

ALLOCATION OF OPERATION & MAINTENANCE EXPENSES
TO RATE GROUPS AND CLASSES OF SERVICE
<u>TOTAL CUSTOMER ACCOUNTS EXP (CONNECTION RELATED)</u>
(DOLLARS IN THOUSANDS)

Row	A CLASS OF SERVICE	B SPECIFIC PROPERTY CODE	C RATE CODE	D NUMBER OF ELECTRONIC LOAD PROFILE METERS	E BILLING EXPENSE	F LPS NUMBER OF INDICATING DEMAND MTRS.	G BILLING EXPENSE	H CIS NUMBER OF INDICATING DEMAND MTRS.	I BILLING EXPENSE	J NUMBER OF ALL OTHER METERS	K BILLING EXPENSE	Z TOTAL METER READING EXPENSE
115	SPECIAL CONTRACTS											
116	METERED PRIMARY - (D)	(6-0)	I 513	15	5	0	0	0	0	0	0	5
117	METERED PRIMARY		454	0	0	0	0	0	0	0	0	0
118	**TOTAL PRIMARY SERVICE-COMMON SYSTEM**			**249**	**84**	**3**	**0**	**0**	**0**	**0**	**0**	**84**
120	PRIMARY SERVICE FROM THE BULK SYSTEM											
121	RATE LLF											
122	METERED PRIMARY		157	0	0	0	0	0	0	0	0	0
124	RATE HLF											
125	METERED PRIMARY	(2)	458	7	2	0	0	0	0	0	0	2
126	METERED PRIMARY - RTP (J)	(9-2)	I 502	1	0	0	0	0	0	0	0	0
127	METERED PRIMARY - RTP (K)	(9-2)	I 458	2	1	0	0	0	0	0	0	1
128	METERED TRANSMISSION - (W)	(2)	I 458	1	0	0	0	0	0	0	0	0
130	SPECIAL CONTRACTS											
131	METERED PRIMARY - (L)	(6-2)	C 601	1	0	0	0	0	0	0	0	0
132	METERED PRIMARY - (X)	(6-5)	I 520	1	0	0	0	0	0	0	0	0
133	METERED PRIMARY - NON-FIRM - (X)		NF	0	0	0	0	0	0	0	0	0
134	**TOTAL PRIMARY SERVICE - BULK SYSTEM**			**13**	**3**	**0**	**0**	**0**	**0**	**0**	**0**	**3**
135	**TOTAL PRIMARY SERVICE**			**262**	**87**	**3**	**0**	**0**	**0**	**0**	**0**	**87**
136	**TOTAL SECONDARY AND PRIMARY SERVICE**			**1,140**	**395**	**4,538**	**252**	**19,088**	**1,058**	**708,133**	**4,619**	**6,324**
138	**TRANSMISSION SERVICE**											
139	TRANSMISSION SERVICE FROM THE COMMON SYSTEM											
140	RATE LLF											
141	METERED PRIMARY		158	0	0	0	0	0	0	0	0	0
142	METERED PRIMARY	(3)	158	4	1	0	0	0	0	0	0	1
143	METERED TRANSMISSION		158	1	0	0	0	0	0	0	0	0
144	METERED TRANSMISSION - RTP (R)	(9-3)	158	1	0	0	0	0	0	0	0	0
146	RATE HLF											
147	METERED PRIMARY	(3)	455	6	2	0	0	0	0	0	0	2
148	METERED PRIMARY - RTP (AH)	(9-0)	455	1	0	0	0	0	0	0	0	0
149	METERED PRIMARY - RTP	(9-3)	455	0	0	0	0	0	0	0	0	0
150	METERED TRANSMISSION		455	0	0	0	0	0	0	0	0	0
151	METERED TRANSMISSION	(3)	455	4	1	0	0	0	0	0	0	1
152	METERED TRANSMISSION - RTP (AA)	(9-3)	455	1	0	0	0	0	0	0	0	0
153	METERED TRANSMISSION	(4)	455	1	0	0	0	0	0	0	0	0
154	METERED TRANSMISSION - RTP (Z)	(9-4)	455	1	0	0	0	0	0	0	0	0
155	METERED TRANSMISSION - TOU (N)	(8-4)	451	1	0	0	0	0	0	0	0	0
156	**TOTAL TRANS.SERVICE - COMMON SYSTEM**			21	**4**	0	**0**	0	**0**	0	**0**	**4**

PSI ENERGY, INC.

RETAIL COST OF SERVICE STUDY

ALLOCATION OF OPERATION & MAINTENANCE EXPENSES
TO RATE GROUPS AND CLASSES OF SERVICE
TOTAL CUSTOMER ACCOUNTS EXP (CONNECTION RELATED)
(DOLLARS IN THOUSANDS)

A	B	C	D	E	F	G	H	I	J	K	Z
CLASS OF SERVICE	SPECIFIC PROPERTY CODE	RATE CODE	NUMBER OF ELECTRONIC LOAD PROFILE METERS	BILLING EXPENSE	LPS NUMBER OF INDICATING DEMAND MTRS.	BILLING EXPENSE	CIS NUMBER OF INDICATING DEMAND MTRS.	BILLING EXPENSE	NUMBER OF ALL OTHER METERS	BILLING EXPENSE	TOTAL METER READING EXPENSE
TRANSMISSION SERVICE FROM THE BULK SYSTEM											
RATE LLF											
METERED PRIMARY	(5)	158	1	0	0	0	0	0	0	0	0
METERED PRIMARY - RTP (U)	(9-1)	158	1	0	0	0	0	0	0	0	0
METERED TRANSMISSION	(1)	158	1	0	0	0	0	0	0	0	0
METERED TRANSMISSION	(5)	158	1	0	0	0	0	0	0	0	0
SPECIAL CONTRACTS :											
METERED PRIMARY - (O)											
FIRM POWER	(6-5)	I 508	1	0	0	0	0	0	0	0	0
TRANSMISSION - INTERRUPTIBLE	(6-5)	I 510	0	0	0	0	0	0	0	0	0
TOTAL			1	**0**	0	**0**	0	**0**	0	**0**	**0**
METERED PRIMARY - NON - FIRM POWER - (O)		NF	0	0	0	0	0	0	0	0	0
METERED PRIMARY		158	0	0	0	0	0	0	0	0	0
METERED TRANSMISSION - (AG)	(1)	I 525	1	0	0	0	0	0	0	0	0
METERED TRANSMISSION - NON - FIRM - (AG)		NF	0	0	0	0	0	0	0	0	0
RATE HLF											
METERED PRIMARY	(1)	456	4	1	0	0	0	0	0	0	1
METERED PRIMARY	(5)	456	1	0	0	0	0	0	0	0	0
METERED TRANSMISSION	(1)	456	3	1	0	0	0	0	0	0	1
METERED TRANSMISSION	(2)	455	2	1	0	0	0	0	0	0	1
METERED TRANSMISSION	(5)	456	1	0	0	0	0	0	0	0	0
METERED TRANSMISSION - RTP (V)	(9-5)	456	2	1	0	0	0	0	0	0	1
METERED TRANSMISSION - TOU (P)	(8-1)	452	0	0	0	0	0	0	0	0	0
TOTAL TRANS. SERVICE - BULK SYSTEM			**19**	**4**	**0**	**0**	**0**	**0**	**0**	**0**	**4**
TOTAL TRANSMISSION SERVICE			**40**	**8**	**0**	**0**	**0**	**0**	**0**	**0**	**8**
TOTAL COMPANY -- RETAIL SALES			**1,180**	**$403**	**4,538**	**$252**	**19,088**	**$1,058**	**708,133**	**$4,619**	**$6,332**
ALLOCATION FACTOR				0.341525424		0.055531071		0.055427494		0.006522786	
ALLOCATOR											
ALLOCATED											
				165		197		1,050		3,943	
ROUNDING DIFFERENCE				9		2		0		0	
ROUNDING ROW CHECK				OK		OK		OK		OK	
TOTAL COMPANY RETAIL CHECK - DOWN				OK		OK		OK		OK	
MISCELLANEOUS CHECKS - TIE TO F&R											

(1) SPECIFIC PROPERTY CODE
0 - NO SPECIFIC PROPERTY - COMMON
1 - BULK LINES
2 - BULK SUBSTATIONS
3 - COMMON LINES
4 - COMMON SUBSTATIONS
5 - NO SPECIFIC PROPERTY - BULK
6 - SPECIAL CONTRACT
6-X - SPECIAL CONTRACT W/SPECIFIC PROPERTY
7 -ENERGY CALL OPT (PRIOR TO 1-96 WAS DMD SIDE MGT)
8 - TIME OF USE CUSTOMERS
9 - REAL TIME PRICING
X - SPECIFIC PROPERTY CODE APPLICABLE

PSI ENERGY, INC.

RETAIL COST OF SERVICE STUDY

ALLOCATION OF OPERATION & MAINTENANCE EXPENSES
TO RATE GROUPS AND CLASSES OF SERVICE
TOTAL CUSTOMER ACCOUNTS EXP (CONNECTION RELATED)
(DOLLARS IN THOUSANDS)

	A	B	C	D	E	F	G	H	I	J	K	Z
16	CLASS OF SERVICE	SPECIFIC PROPERTY CODE	RATE CODE	NUMBER OF ELECTRONIC LOAD PROFILE METERS	BILLING EXPENSE	LPS NUMBER OF INDICATING DEMAND MTRS.	BILLING EXPENSE	CIS NUMBER OF INDICATING DEMAND MTRS.	BILLING EXPENSE	NUMBER OF ALL OTHER METERS	BILLING EXPENSE	TOTAL METER READING EXPENSE
211	**MEMO ITEMS**											
213	**TOTAL RATE RS**			0	0	0	0	0	0	638,671	4,166	4,166
215	**TOTAL CS AND FOC**			0	0	0	0	0	0	67,607	441	441
217	TOTAL LLF SECONDARY SERVED			311	106	975	53	19,088	1,058	0	0	1,217
218	TOTAL LLF PRIMARY SERVED FROM COMMON			67	22	3	0	0	0	0	0	22
219	TOTAL LLF PRIMARY SERVED FROM BULK			0	0	0	0	0	0	0	0	0
220	TOTAL LLF TRANSMISSION SERVED FROM COMMON			6	1	0	0	0	0	0	0	1
221	TOTAL LLF TRANSMISSION SERVED FROM BULK			4	0	0	0	0	0	0	0	0
222	**TOTAL LLF**			388	129	978	53	19,088	1,058	0	0	1,240
224	SPECIAL CONTRACTS:											
225	METERED PRIMARY - BULK - (L)			1	0	0	0	0	0	0	0	0
226	METERED PRIMARY - COMMON - (D)			15	5	0	0	0	0	0	0	5
227	METERED SECONDARY - COMMON - (AF)			0	0	0	0	0	0	0	0	0
228	METERED PRIMARY - BULK - (O)			1	0	0	0	0	0	0	0	0
229	METERED PRIMARY - NON-FIRM - BULK - (O)			0	0	0	0	0	0	0	0	0
230	METERED PRIMARY - BULK - (X)			1	0	0	0	0	0	0	0	0
231	METERED PRIMARY - NON-FIRM - BULK - (X)			0	0	0	0	0	0	0	0	0
232	METERED TRANSMISSION - BULK - (AG)			1	0	0	0	0	0	0	0	0
233	METERED TRANSMISSION - NON-FIRM - BULK - (AG)			0	0	0	0	0	0	0	0	0
235	TOTAL HLF SECONDARY SERVED			567	202	3,560	199	0	0	0	0	401
236	TOTAL HLF PRIMARY SERVED FROM COMMON			167	57	0	0	0	0	0	0	57
237	TOTAL HLF PRIMARY SERVED FROM BULK			11	3	0	0	0	0	0	0	3
238	TOTAL HLF TRANSMISSION SERVED FROM COMMON			15	3	0	0	0	0	0	0	3
239	TOTAL HLF TRANSMISSION SERVED FROM BULK			13	4	0	0	0	0	0	0	4
240	**TOTAL HLF**			773	269	3,560	199	0	0	0	0	468
242	**TOTAL COMMERCIAL AND INDUSTRIAL**			1,180	403	4,538	252	19,088	1,058	67,607	441	3,862
244	**TOTAL ALL OTHER**			0	0	0	0	0	0	1,855	12	12
246	**TOTAL COMPANY**			1,180	403	4,538	252	19,088	1,058	708,133	4,619	6,332

ATTACHMENT KLO-5

OUCC
IURC Cause No. 44963
Data Request Set No. 1
Received: July 24, 2017

OUCC 1.11

Request:

Duke previously estimated net savings associated with the AMI project as $39.69 million over 7 years. Is that still an accurate projection? If not, please provide an updated estimate with an explanation of any changes. When does Duke expect the AMI benefits to begin? Please provide a breakdown of the total projected benefits by year. Please also provide itemized annual estimates of the dollar amounts Duke subtracts from its estimated annual benefits to calculate the projected annual net benefits from the AMI projects, which together would total $39.69 million over 7 years.

Objection:

Duke Energy Indiana objects to this request as such information is not relevant to this proceeding and not reasonably calculated to lead to admissible evidence. Duke Energy Indiana has not submitted a cost/benefit analysis in the proceeding. Further, Duke Energy Indiana objects to this request to the extent it seeks a calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing. Finally, the OUCC is a party to a settlement agreement wherein it was agreed that the OUCC would not oppose AMI deployment in Duke Energy Indiana's service territory and that Duke Energy Indiana would retain any net savings related to its AMI deployment until the next base rate case. See IURC Cause No. 44720.

ATTACHMENT KLO-6

OUCC
IURC Cause No. 44963
Data Request Set No. 3
Received: August 31, 2017

OUCC 3.3

Request:

Does DEI currently have AMR meters installed and operational?

a. If so, how many?
b. If so, were customers charged individually for the AMR meter, its installation cost, or a monthly fee? If so, please identify the respective individual amounts.
c. Please explain how DEI recovered the cost for the AMR meters and installation.

Response:

a. Duke Energy Indiana has 22,147 AMR meters that can be read remotely via a handheld device held by someone close enough to a meter.

b. No, Duke Energy Indiana installed those meters at its own initiative due to meter access issues or employee safety concerns.

c. Duke Energy Indiana has not received any special ratemaking recovery for these costs.

Witness: Justin Brown / Jeff Bailey

ATTACHMENT KLO-7

OUCC
IURC Cause No. 44963
Data Request Set No. 3
Received: August 31, 2017

OUCC 3.4

Request:

If a customer's meter ceased to operate properly, for which of the following was a customer charged for the meter or its replacement installation and what was the customer's respective costs?

a. Manual Read to Manual Read
b. Manual Read to AMR
c. Manual Read to AMI
d. AMR to AMR
e. AMR to AMI
f. AMI to AMI

Response:

Customers are not charged for meters that must be replaced because they have ceased to operate properly.

Witness: Justin Brown

ATTACHMENT KLO-8

OUCC
IURC Cause No. 44963
Data Request Set No. 3
Received: August 31, 2017

OUCC 3.6

Request:

What is the average estimated useful life (in years) of each of the following types of meters?

a. Manual Read
b. AMR
c. AMI

Response:

a. The estimated useful life assumed for non-AMI meters in Duke Energy Indiana's latest approved depreciation rates was 35 years. There was not a separate depreciation rate for Manual Read vs. AMR meters.
b. See response to part (a) above.
c. As approved in the order in Cause No. 44720 (TDSIC Plan), Duke Energy Indiana's AMI meters have a depreciation rate based on a 15 year useful life. This would be the case whether the AMI meters are installed as planned or with radio communications disabled as a result of a customer opt-out, should the opt-out option be approved by the Commission in this proceeding.

ATTACHMENT KLO-9

OUCC
IURC Cause No. 44963
Data Request Set No. 1
Received: July 24, 2017

OUCC 1.6

Request:

Referring to Petitioner's Exhibit 1, page 6, Mr. Brown states Duke may install either an AMI meter with the RF communication capability disabled or other non-communicating meter. Please describe Duke's criteria for deciding what type of meter to install.

Response:

Duke Energy Indiana plans to use an AMI meter with the RF communication capability disabled for its opt-out customers, unless or until there is some unforeseen reason why that solution would not be practicable.

Witness: Justin Brown