ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

INVESTIGATION OF THE INDIANA UTILITY REGULATORY COMMISSION, OF SMART GRID INVESTMENTS AND SMART GRID INFORMATION ISSUES CONTAINED IN 111(d) OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 (16 U.S.C. 2621(d)), AS AMENDED BY THE ENERGY INDEPENDENCE AND SECURITY ACT OF 2007.	)	**CAUSE NO. 43580**
	)	**APPROVED:** DEC 1 6 2009
RESPONDENTS: HARRISON COUNTY AND NORTH-EASTERN REMC, THE CITIES OF ANDERSON, AUBURN, MISHAWAKA, AND RICHMOND, INDIANA MICHIGAN POWER COMPANY, INDIANAPOLIS POWER & LIGHT COMPANY, NORTHERN INDIANA PUBLIC SERVICE COMPANY, DUKE ENERGY INDIANA, INC. AND SOUTHERN INDIANA GAS & ELECTRIC COMPANY	)	

<u>BY THE COMMISSION:</u>
David E. Ziegner, Commissioner
Aaron A. Schmoll, Administrative Law Judge

On October 8, 2008, the Indiana Utility Regulatory Commission ("Commission") initiated an investigation of Smart Grid Investments and Smart Grid Information issues contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)), as amended by the Energy Independence and Security Act of 2007.

Anderson Municipal Light & Power ("Anderson"), City of Auburn, Indiana ("Auburn"), Mishawaka Utilities ("Mishawaka") and Richmond Power & Light ("Richmond") (Anderson, Auburn, Mishawaka and Richmond collectively referred to herein as "Municipal Utilities"); Indiana Michigan Power Company ("I&M"); Duke Energy Indiana, Inc. ("Duke Energy Indiana"), Indianapolis Power & Light Company ("IPL"), Northern Indiana Public Service Company ("NIPSCO"), Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren"), Northeastern Rural Electric Membership Corporation ("Northeastern REMC") and Harrison County Rural Electric Membership Corporation ("Harrison REMC"), were named Respondent Utilities. Indiana Industrial Group ("Industrial Group"), Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Wal-Mart Stores East, LP and Sam's East, LP ("Wal-Mart"), Nucor Steel, a division of Nucor Corporation ("Nucor"), and Steel Dynamics, Inc. ("SDI") all filed petitions to intervene, which the Presiding Officers granted via Docket Entries. On April 7, 2009, Indiana Telecommunications Association ("ITA") filed its petition to intervene. On April 14, 2009, Respondent Utilities filed its objections to the ITA's petition to intervene. ITA filed its reply on April 21, 2009. By Docket Entry dated April 24, 2009, the Presiding Officers granted ITA's petition to intervene.

Pursuant to notice, duly published as required by law, an Prehearing Conference and Preliminary Hearing was held on October 21, 2008 at 9:30 a.m. in Room 222 of the National City Center, 101 W. Washington Street, Indianapolis, Indiana. Respondent Utilities, CAC, and the OUCC appeared by their respective counsel. No other members of the public appeared.

On November 6, 2008, the Commission issued a Prehearing Conference Order which, among other things, established a procedural schedule for this Cause. In accordance with the procedural schedule, on December 12, 2008, Respondent Utilities and the Office of Utility Consumer Counselor ("OUCC") each filed a list of issues that each party believed should be addressed in this Cause, and the parties filed responses on January 16, 2009. On February 10, 2009, the Presiding Officers issued a Docket Entry containing the issues that would be subject to this proceeding. On February 19, 2009, the parties participated in a Technical Workshop and on March 13, 2009, the Respondent Utilities and the OUCC each filed a Report outlining discussions of the issues addressed at the Technical Workshop. The parties prefiled initial testimony on April 7, 2009 and responsive testimony on May 7, 2009.

Pursuant to notice, duly published as required by law, an Evidentiary Hearing was held on June 8, 2009 at 9:30 a.m. in Room 222 of the National City Center, 101 W. Washington Street, Indianapolis, Indiana. Respondent Utilities, Industrial Group, Hoosier Energy, CAC, Wal-Mart, Nucor, SDI, ITA and the OUCC appeared by their respective counsel. At the hearing the testimony and exhibits of the parties were offered and admitted into the record without objection. No other members of the public appeared. Respondent Utilities, Intervenors and the OUCC filed their proposed orders on July 17, 2009 and reply briefs were filed on September 18, 2009.

This Commission, having examined the evidence and being duly advised in the premises, now finds that:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the Evidentiary Hearing in this Cause was given as required by law. Respondent Utilities are operating public utilities, or rate-regulated municipally owned utilities, within the meaning of those terms in Ind. Code § 8-1-2-1(a) and (h) of the Public Service Commission Act, as amended, and are subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. The Commission has jurisdiction over Respondent Utilities and the subject matter of this Cause.

2. **Purpose of Investigation.** The Energy Independence and Security Act of 2007 ("EISA"), enacted on December 19, 2007, amended the Public Utility Regulatory Policies Act of 1978 ("PURPA") by adding four (4) new PURPA standards. These standards are reflected under

PURPA subsections 111(d)(16)-(17) and (18)-(19).[1] Sections 111(d)(16)-(17) generally address (1) Integrated Resource Planning issues; and (2) Rate Design Modifications to Promote Energy Efficiency Investments. Consideration of each of these issues is being undertaken by the Indiana Utility Regulatory Commission ("Commission") as part of Phase II of its Demand Side Management ("DSM") Investigation in Cause No. 42693. Subsections (18)-(19) address (1) Consideration of Smart Grid Investments; and (2) Smart Grid Information, each of which will be considered by the Commission in this Cause.

Section 111(d)(18) provides that the Commission shall consider the following standard of smart grid investments:

> (18) CONSIDERATION OF SMART GRID INVESTMENTS-
> (A) IN GENERAL- Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including—
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> (i) total costs;
> (ii) cost-effectiveness;
> (iii) improved reliability;
> (iv) security;
> (v) system performance; and
> (vi) societal benefit.
>
> (B) RATE RECOVERY- Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified smart grid system.
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> (C) OBSOLETE EQUIPMENT- Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

16 U.S.C. § 2621(d)(18)(A)-(C).

Section 111(d)(19) provides that the Commission shall consider the following standard for smart grid information:

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[1] Section 408 of the American Recovery and Reinvestment Act of 2009 (Pub. L. 111-5) corrected the duplication error of the numbering provisions previously noted in the Commission's October 8, 2008 Order opening this investigation.

(19) SMART GRID INFORMATION-

(A) STANDARD- All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph (B).

(B) INFORMATION- Information provided under this section, to the extent practicable, shall include:

(i) PRICES- Purchasers and other interested persons shall be provided with information on--

(I) time-based electricity prices in the wholesale electricity market; and

(II) time-based electricity retail prices or rates that are available to the purchasers.

(ii) USAGE- Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them.

(iii) INTERVALS AND PROJECTIONS- Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

(iv) SOURCES- Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

(C) ACCESS- Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.

16 U.S.C. § 2621(d)(19)(A)-(C).

PURPA requires each state regulatory authority (with respect to electric utilities for which it has ratemaking authority) to (1) consider each of these standards, and (2) make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this chapter. The purposes of this chapter are: (1) conservation of energy supplied by electric utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers. 16 U.S.C. § 2611.

3. Direct Testimony.

A. Utility Group – Joint Testimony. In order to avoid duplication in the record and as encouraged by the presiding officers at the prehearing conference, Anderson, Auburn, Duke Energy Indiana, I&M, IPL, Mishawaka, NIPSCO, Richmond, and Vectren ("Utility Group"), joined together to present joint testimony in response to the issues outlined in the September 29, 2006 Docket Entry in this Cause ("Joint Ex. 1").

In its testimony, the Utility Group recommends that the EISA Standards not be adopted by the Commission. The Utility Group states that adoption of the EISA Standards is unnecessary by this Commission as it presently possesses sufficient authority under existing statutes and regulations to ensure that energy efficiency resources are considered and timely cost recovery provided. Although the Utility Group believes it is unnecessary for the Commission to adopt the proposed standards, the Utility Group believes the Commission should permit utilities to timely recover the costs associated with Smart Grid technologies. See Joint Ex. 1, pp. 31-32.

(i) Proposed Smart Grid Investment Standard. Although the Utility Group recognized the intended limits of this proceeding, they believe that it is necessary to understand what constitutes a "Qualified Smart Grid System" in considering the EISA Standards. In an attempt to define what constitutes a "Smart Grid," the Utility Group examined the characteristics noted in the EISA as well as the key characteristics of a "Modern Grid" as outlined by the U.S. Department of Energy ("DOE"). The Utility Group stated that the DOE defines a "Qualified Smart Grid System" in terms of the following broad characteristics, rather than discrete functions or technologies: (1) self-heals to minimize downtime and financial loss; (2) motivates and includes the consumer with visible pricing and program choices; (3) built-in security to resist attack; (4) provides power quality for 21st century needs; (5) accommodates all generation and storage options, including renewable energy; (6) enables markets to operate consistently while allowing innovation locally and regionally; and (7) optimizes assets and operates efficiently. The Utility Group testified that they agree with the DOE approach and believe Indiana should similarly promote a broad interpretation of a "Qualified Smart Grid System" that allows utilities flexibility to implement a variety of technologies in ways that benefit customers and help achieve the many goals identified by the DOE. The Utility Group further recognized that an accepted definition will continue to develop as a result of The American Recovery and Reinvestment Act of 2009 (the "ARRA"), which designates significant federal funding for Smart Grid projects. The Utility Group believes that they and the Commission will benefit from monitoring the ARRA process as the DOE and other regulators entertain Smart Grid applications and consider the costs and benefits of the proposals and how they match recommended criteria for projects to be treated as "Smart Grid" in nature. *See* Joint Ex. 1, pp. 4-8.

(a) In General. In considering the EISA Smart Grid Investments Standard, the Utility Group testified that the Commission should not require an electric utility, prior to undertaking investments in nonadvanced grid technologies, to demonstrate to the Commission that it has considered an investment in a Qualified Smart Grid System based on the seven factors set forth in the EISA Standard. The Utility Group stated that given the dynamic evolution of technical devices and supporting software systems, there is not a "bright line" that distinguishes when advanced technologies should be developed. Individual electric utilities base a decision to deploy advanced technologies upon consideration of many aspects of utility operations as a means to accomplish its appropriate long-term plan. The Utility Group testified that utilities should continue to analyze non-advanced technology investments prior to making significant system deployments and present this evidence to the Commission if a utility seeks cost recovery from customers. The Commission would have an opportunity to review this analysis in the course of approving cost recovery. However, the Utility Group noted that routine replacements of equipment such as meters, transformers, capacitors and reclosers are an expected regular necessity to continue reliable service and do not currently require Commission approval to determine whether such replacements are necessary. See Joint Ex. 1, pp. 10-11.

The Utility Group testified that when evaluating the option value of putting in place an advanced grid technology compared to the available nonadvanced alternatives, it may not be practicable for the Commission to evaluate the option value using a standard analysis tool due to the wide array of objectives, existing systems and available technological options. A utility may address advanced grid technology and subsequent investment plans as part of its Integrated Resource Plan. *Id.*

The Utility Group testified that the cost and benefit components to be considered with regard to Smart Grid Investments may include components similar to DSM tests, such as equipment costs, avoided energy and demand savings, and reliability improvements, as well as operational expenses and benefits depending upon the objective expected to be achieved by each planned technological solution. In addition, more intangible customer and societal benefits could be considered, as supported by EPRI. The Utility Group also stated that although there may be benefits from reporting the benefits achieved as a result of Smart Grid deployments, any reporting requirements imposed by the Commission should be established only after a careful consideration of the specific purpose of the information and the cost to prepare the report. While the Utility Group agrees that on-going consumer education about the "Smart Grid" is important, it should be the responsibility of each utility to communicate to its customers the benefits related to the rollout of new specific technologies as they occur. See Joint Ex. 1, pp. 11-14.

(b) Rate Recovery. The Utility Group testified that the Commission should allow timely cost recovery relating to any capital, operating expenditure, consumer education or other costs relating to the deployment of a Smart Grid System, including a reasonable rate of return on the capital expenditures. The Utility Group stated that this should be done via a rate adjustment mechanism and without the need for a base rate case, which would serve as a deterrent to investments in advanced technology in comparison to implementation of a rate adjustment mechanism. The Utility Group testified that the appropriate statutory basis for the Commission's consideration of cost recovery of Smart Grid Investments is the Alternative Utility Regulation Statute (IC 8-1-2.5 *et seq.*). The Utility Group proposed the following preferred option for cost recovery, consistent with Indiana's Strategic Energy Plan of 2006:

> Following initial Commission approval to proceed with a Smart Grid plan, project funding should commence through a Commission-approved rate adjustment

> mechanism. Funding would consist of the recovery through the rate adjustment mechanism of a carrying cost on capital investment (with no accrual of Allowance for Funds Used During Construction once costs are being recovered via the adjustment mechanism) that should continue until the project is placed in service and reviewed by the Commission in a review and reconciliation proceeding. After the in-service date and Commission review, recovery on and of the investment, along with associated operating costs, would commence through the rate adjustment mechanism. With periodic filings and Commission review, reconciliations would occur for updated or final project cost, any acceleration or delay in project completion, and to set a new factor for the rate adjustment mechanism. The cost of the completed capital project would be included in rate base in the utility's next general rate case.

Id. at 16-17.

The Utility Group is less supportive of Smart Grid cost recovery through a traditional base rate case, as this non-cash approach could impact the Utility Group's ability to raise sufficient capital to implement such a project, and the project would continue to compete with other capital needs of the utility. In addition, the Utility Group stated that there is no way to time a general rate case (or cases) to capture these types of investments without the utility suffering material earnings and cash flow erosion in the process, to the potential detriment of its credit quality.

The Utility Group suggests that rather than the Commission developing a set of independent standards related to Smart Grid implementations and associated cost recovery, the Commission should encourage utilities to adopt the following core functions in their implementations, which may be staged: (1) remote reading of meters; (2) remote disconnect/reconnect capability up to a 200 amp rating; (3) net metering support; (4) remote capability to upgrade meter software; (5) energy usage monitoring tools; (6) communication support with in-home devices; and (7) outage notification and restoration confirmation. The Utility Group stated that these core functions will ensure that customers have the most cost-effective technology solutions and are not locked into a unique solution that is costly and difficult to maintain. In addition, the Utility Group suggests that if the Commission desires to include specific technology standards, a well-defined waiver process should be included that allows for a utility to provide evidence to support how waiving the requirements is in the public interest. *See* Joint Ex. 1, pp. 17-19.

The Utility Group testified that Smart Grid investments and operating expenses should be appropriately allocated to each utility's customer classes, subject to Commission review and commensurate with the benefits customers would receive. The Utility Group also stated that they believe the Commission should authorize utilities to recover the following Smart Grid costs concurrent with installation and operation: (1) capital costs and a return on the investment at the utility's authorized rate of return; (2) implementation, operating, marketing, education, and other required deployment expenses; (3) depreciation for capital investments associated with hardware, meters, accompanying data transmission systems, data management infrastructure, and software, based on depreciable lives established by the Commission; (4) operation and maintenance expenses related to the investment, including property taxes (or payments in-lieu of property taxes), reduced by any achieved and quantifiable operational savings that result from deployment; (5) net book value of any obsolete equipment removed and replaced as a result of deployment; (6) any additional costs associated with updating systems or other direct or indirect costs supporting a new program; and (7) for municipally owned utilities, debt service on any financing associated with the acquisition and installation of Smart Grid technology. The Utility Group also stated that considering some of these projects are being done today, on-going operation and maintenance expenses related to the Smart Grid investment, reduced by any direct operational savings that may result, should be determined and treated as incremental to costs reflected in existing base rates until such time as a base rate case is otherwise required by the installing utility. *See* Joint Ex. 1, pp. 19- 21.

(c) Obsolete Equipment. As to obsolete equipment, the Utility Group recommended that the Commission authorize the timely recovery of the remaining book value costs of the obsolete equipment over the remaining depreciable life of the equipment or, alternatively, an accelerated period should be determined by the specific utility, with approval of the Commission. *See* Joint Ex. 1, pp. 21-23.

(ii) Proposed Smart Grid Information Standard. The Utility Group testified that as it applies to wholesale prices, the federal standard is unnecessary and should not be adopted. The Utility Group explained that, with the exception of the municipally owned electric utilities, each member of the Utility Group is also a member of a Regional Transmission Organization ("RTO"). Although information regarding wholesale prices is made available to wholesale purchasers through the RTO, Indiana customers receive electric service through retail rates, not the RTO wholesale prices. The Utility Group stated that any requirement that the Utilities provide such information regarding wholesale prices would potentially result in confusion.

While the Utility Group testified that it does not object to making retail price information available, Utility rate information is already available to Indiana consumers through each Utility's website, the Commission's website (through access to utility tariff filings) and each Utility's customer service or account representatives. In addition, the Utility Group stated that customer usage information, including on peak and off peak usage, is already available in customer's monthly bills. As additional time-based tariffs become available, the Utility Group stated that it would anticipate making the corresponding time-based pricing information, including daily and hourly information, available to retail customers. The Utility Group believes that adopting a requirement that each Utility make such information available prior to any need for it could cause confusion and would impose unnecessary costs on retail consumers. The Utility Group also pointed out that there are several types of barriers that exist to providing this information, such as technological, behavioral, cost and regulatory barriers. *See* Joint Ex. 1, pp. 24-28.

The Utility Group stated that it is difficult to identify costs and related benefits associated with different forms of customer information access due to the evolution of the market and company specific requirements. Each Utility would need to analyze costs and related benefits on an individual basis. The Utility Group also stated according to various studies, if customers are not on some form of a time-based rate, consumers will adjust their consumption behavior based on access to usage date without rate based incentives ("Prius Effect"). Consumers simply having more robust and frequent usage information access will use less. *Id.* at 29.

The Utility Group testified that it does not believe the Commission needs to adopt the EISA Information Standard at this time. The Utility Group stated that Indiana utilities will likely propose different types of advanced technology systems with different capabilities, and the Commission should decide whether each proposal fits the needs of each utility and its customers on a case-by-case basis depending, in part, on whether the cost of providing the information to customers is justified. *Id.* at 30.

B. Utility Group – Company-Specific Testimony. The following members of the Utility Group also presented company-specific direct testimony.

(i) Duke Energy Indiana. Todd W. Arnold, Senior Vice President, SmartGrid and Customer Systems, of Duke Energy Business Services LLC, testified that Duke Energy Indiana supports the EISA Standards related to smart grid investments and information, but does not believe these standards must be formally adopted by the Commission. He stated that instead, the factors set forth in the EISA Smart Grid Investment Standard should be considered in implementation of a utility's smart grid proposal, just as Duke Energy Indiana has independently considered each of them in evaluating its own Smart Grid Initiative proposal in Cause No. 43501. He described Duke Energy Indiana's Smart Grid Initiative and explained how Duke Energy Indiana already considered total cost, cost effectiveness, societal benefits, improved reliability, security measures, and enhanced system performance. He stated that a well thought out smart grid proposal will necessarily consider the EISA investment factors, even without a Commission mandate.

As to the EISA Information Standard, Mr. Arnold stated that Duke Energy Indiana does not believe it is necessary for the Commission to adopt the standard at this time. He explained that to some extent, Duke Energy Indiana already provides the information and access provided for in this EISA Standard. He stated that Duke Energy Indiana currently offers a time of use rate for its LLF and HLF customers (Standard Contract Riders 10.2 and 12.2), and has expressed an interest in time of use pricing pilots and testing other various information offers as part of its Smart Grid Initiative proposal in Cause No. 43501. He further explained that Duke Energy Indiana customers that have demands greater than 500 kW are generally metered using interval metering devices. He stated that the interval data is not only available internally for statistical analysis and billing purposes, but is also available to customers via an online tool through the "My Duke Energy" web portal.

Mr. Arnold also testified that Duke Energy Indiana anticipates applying for federal stimulus dollars available under the ARRA related to its Smart Grid Initiative as proposed in Cause No 43501. He stated that the ARRA provides funding for demonstration projects and smart grid investments in the form of 50% matching funds. The DOE will distribute the funds on a competitive basis. He stated that it is also possible that demonstration projects utilizing smart grid technology which enable energy efficiency, renewable distributed generation projects, or plug-in hybrid electric vehicles may be eligible for ARRA funds distributed to the states and localities. Duke Energy Indiana also anticipates applying for 50% matching funds for the renewable distributed generation demonstration that it proposed as part of its Smart Grid Initiative.

(ii) I&M. Kent D. Curry, Director of Regulatory Services for I&M, addressed the anticipated rate impact from the timely recovery of the cost of obsolescence associated with upgrading current distribution systems to that of a "qualified smart grid system" based on the current vintage of I&M's electric system. Mr. Curry explained that I&M is currently focused on its 10,000-meter Smart Metering Pilot Program (SMPP) in the South Bend area and any plans for further expansion of smart metering beyond this pilot area, possibly resulting in additional obsolescence, will be developed at least in part upon I&M's experience with this pilot.

Mr. Curry also discussed the degree to which information is available to consumers. Mr. Curry stated that I&M's retail rates, including on-peak and off-peak rates, and I&M's tariffs associated with the SMPP are available on I&M's website. He also stated that customers may contact I&M's Customer Solutions Center or view their 36-month usage history on I&M's website. Mr. Curry stated that all customers in the SMPP area will have a Smart Meter that will provide access to more information (kWh consumption on a daily, weekly, and monthly basis, and on an hourly basis with a one-day lag) via the internet about how the customer's home or business uses electricity.

Mr. Curry stated that I&M industrial customers electing service on an interruptible or experimental real-time pricing tariff are provided pricing information affording the customer the opportunity to make decisions regarding the curtailment or shifting of load.

As to the potential use of federal stimulus funds, Mr. Curry stated that I&M is presently dedicated to the successful deployment of the 10,000-meter SMPP in the South Bend area. He noted that the experience with this deployment is expected to be useful in determining the Company's future plans for any further deployment of smart meter technology during its developmental period.

(iii) IPL. Ken Flora, Director of Regulatory Affairs for IPL, stated that IPL is developing a migration plan to deploy advanced technologies that achieve specific objectives over the next several years. Mr. Flora stated that IPL currently uses automated meters for approximately 98% of its system and a significant number of distribution automation devices could be leveraged through a two-way system to achieve advanced functionality and minimize expenses as much as possible. He stated that IPL is also researching other technologies that would provide real-time energy consumption information to energy-only metered customers (Home Area Networks or "HAN").

Mr. Flora stated that IPL provides pricing information in its filed tariffs upon request to customers and that a time-of-use commercial rate is currently available but is not widely selected by customers. He stated that IPL's 6,400 demand-metered customers have, or will have, access through the IPL website to historic load information from 15 minute interval data based on billing cycle history. In addition, between 1 and 2% of these customers receive pulse signals directly from the existing meters for use in their own energy management systems. Mr. Flora testified that IPL is investigating technical solution options to provide "near real time" usage data to these demand-metered customers as part of its active Advanced Metering Infrastructure (AMI) Proof of Concept (POC).

Mr. Flora stated that costs vary based on the vintage of existing hardware and software systems and what functionality is desired. He stated that in order to improve the accessibility of usage information for residential and small business energy-only metered customers, IPL has proposed a HAN POC as a separate and distinct component of its Advanced DSM plan through its pending DSM proceeding (IURC Cause No. 43623). Mr. Flora noted that while the technical feasibility of HAN deployments is being proven throughout the Country, full scale deployments have not yet been achieved. If the HAN POC is successful, IPL plans to deploy in-home displays with "real-time" data viewing through connections to meters and possible internet portals for up to 22,000 customers with energy-only meters in Phase II of its DSM proceeding.

Mr. Flora stated that IPL is studying the criteria of stimulus funding components to determine how it may partner with other stakeholders to optimize benefits for IPL customers and the State of Indiana. He stated that IPL was awaiting the publication of the DOE guidelines for Smart Grid funding. In the interim, IPL staff was continuing to gather information from internal and external sources in order to evaluate options for a potential application.

(iv) NIPSCO. Mark G. Small, Director of Engineering of NIPSCO, testified that NIPSCO is currently in the process of selecting a consultant for the purpose of conducting a cost/benefit analysis regarding smart grid technology, AMI and demand response implementation. Mr. Small testified that NIPSCO has Supervisor Control and Data Acquisition (SCADA) in 98% of its transmission substations, but the system does not collect all of the possible data. According to Mr. Small, NIPSCO is in the process of rolling out over 2700 internal data recording meters for commercial customers, but has not implemented AMI technologies.

Mr. Small testified that the components of NIPSCO's distribution system that could be upgraded to that of a "qualified smart grid system" include, but are not limited to, transformers, switches, voltage regulators, capacitors, protective reclosers and sectionalizers. Mr. Small testified that since NIPSCO has not retired any distribution system components before their useful lives have expired, any project involving the removal and replacement of a "legacy" type product with a "qualified smart grid system" type product would require a calculated cost benefit to be developed and would be evaluated on a case by case basis.

Mr. Small testified that AMI would require the replacement of existing meters prior to the end of their useful lives. Because NIPSCO's existing meters are depreciated over a life of thirty years, the replacement of all 450,000 electric meters may result in the premature retirement of approximately 300,000 meters.

Mr. Small testified that NIPSCO does not currently have a mechanism in place which would allow for electricity purchasers to have direct access to the daily updated pricing and usage information noted in EISA Section 1307 (a) (19). However, if NIPSCO, with the Commission's approval, were to adopt the implementation of AMI, this information could be made available to customers, assuming that all security issues are resolved to the degree required or necessary.

According to Mr. Small, NIPSCO is in the beginning stages of researching the various options of making information available to customers. Preliminary findings indicate that the costs of different forms of access varies greatly depending on whether the information is "pulled" by customers or "pushed' to them. Mr. Small testified that NIPSCO is committed to balancing the costs of such access with the benefits it provides.

Mr. Small testified that NIPSCO is in the process of reviewing the federal stimulus funding to determine how those funds could be utilized to upgrade NIPSCO's infrastructure. Mr. Small said that NIPSCO is considering the implementation of a program that would result in the replacement of existing electric meters with Smart Meters, and would also include the infrastructure necessary for two-way communication. Furthermore, NIPSCO is considering Transmission System upgrade projects that would increase transfer capacity and reliability including relaying upgrades and transformer monitoring additions.

(v) Vectren. Robert Sears, Director of Conservation of Vectren, provided information regarding ongoing studies of AMI and demand response being conducted by the Company, and also described the current use of advanced metering in the company system. Mr. Sears also discussed the limited availability of pricing and usage information to its customers due to current technology limitations. He indicated that deployment of Smart Grid technologies, such as advanced metering, would enable the flow of information to customers, and referenced public studies which showed that customers could benefit from receipt of such information in terms of changing their usage patterns. In terms of potential access to ARRA project funding, Mr. Sears stated that the ongoing internal studies would enable Vectren Energy to determine how to prudently approach technology deployment and the availability of ARRA funding based on a careful review of costs and benefits.

C. Respondents Northeastern REMC and Harrison. Gregg L. Kiess, President and CEO of Northeastern Rural Electric Membership Corporation, testified on behalf of Northeastern REMC and Harrison County REMC. He testified that the development and integration of smart grid technology will be an important development in the electric utility program in the next decade. Mr. Kiess said that the Commission must remain mindful that electric distribution cooperatives such as Northeastern REMC and Harrison REMC, along with their respective power suppliers, Wabash Valley Power Association, Inc. and Hoosier Energy, are generally regulated on a cost of service basis rather than on a rate of return basis. Therefore, these cooperatives must assess what improvements to their systems are most efficient, provide the lowest cost to their retail member customers and meet the societal and governmental policy requirements. Mr. Kiess testified that Northeastern REMC and Harrison REMC have concerns that the considerations described in Standard 16 do not always "fit" the electric cooperative model or cooperatives' existing facilities. He said that to mandate a Commission hearing before permitting nonadvanced grid technology to be installed could have direct and seriously detrimental impacts on an electric distribution cooperative.

Mr. Kiess testified that it would make little sense to require advanced grid technology to be installed when repairing an existing distribution line. A more practical approach, in his view, would be to permit electric cooperatives to make their own assessment of the costs and benefits of advanced grid technology without the intervention of the Commission. However, if the Commission does require a hearing before nonadvanced technology is installed, then an expedited process should be adopted for such determinations.

Mr. Kiess testified that recovery of utility investment in capital costs, operating costs or other costs for smart grid deployment should be handled through the method requested by the REMC, which could include an expedited tracker mechanism, a formulaic rate or as part of a routine rate case. Recovery of costs for obsolete equipment should be permitted if a utility determines there is a benefit in installing smart grid technology and retiring nonadvanced technology. According to Mr. Kiess, the Commission should not mandate specific smart grid development but it should allow the cooperative members, through their elected boards, to determine the scope and pace of installation of technology and communications to support a smarter grid than exists today.

D. OUCC. Ronald Keen, Senior Analyst within the Resource Planning, Emerging Technologies, and Telecommunications Division of the OUCC, testified that the OUCC believes the concept of deploying a fully functional smart grid should be the end goal rather than a specific phase or requirement. And, the end goal of each utility must be the deployment of a full-function smart grid at a point in the future in accordance with an overarching master development plan.

Mr. Keen testified that in theory, utilities would develop an overarching 'master' strategy to reach the end goal of deploying a fully-functional smart grid, then develop a detailed plan to achieve that goal through a series of phases to test, evaluate, and operationally deploy segments of technology. Initially, the utility would use some type of pilot program to test and evaluate the technology and any significant policy and operational changes which may be deployed and implemented in the specific phases.

According to Mr. Keen, there is no 'timeframe' when a fully-functional smart grid must be deployed once AMR or AMI technology is introduced into the grid. The timeline should be established by each utility based on its capability, resources and desire to deploy the smart grid in its entirety. Mr. Keen testified that the timeline affords customers an idea of when they can expect to take advantage of the benefits a fully-functional smart grid system will offer.

Mr. Keen testified that the concept of a Smart Grid is the sum of distinct major components (distribution automation, smart meters and home area networks, or HANs) that must be considered separate technologies. Mr. Keen testified that as demand response and Distributed Energy Resources (DER) penetration increases, the lines between the electricity provider and the consumer blur and the exchange of information must become more multi-directional, enabling decisions on whether to "supply" or "use" energy based on dynamic rather than static prices. Mr. Keen testified that as either an independent or integrated component of a Smart Grid, advanced distribution automation (ADA) automates and enhances the reliability of power system service, power quality, and system efficiency through data preparation in near-real-time; optimal decision-making; and the control of distribution operations in coordination with transmission and generation systems operations.

Mr. Keen testified that a "smart meter" is an advanced meter which identifies consumption in more detail than a conventional meter and has the capability to communicate the information via a dedicated network to the utility for monitoring and billing purposes. He stated that an advanced meter reading (AMR) system does not necessarily require the deployment of a "smart meter." Mr. Keen testified that because the functionality offered through AMR, including one-way communication for meter reading, basic theft detection and outage restoration detection, the OUCC believes there is little need for the Commission to establish minimum standards of functionality requirements regarding deployed AMR systems, except to ensure they operate using an open standards architecture to enable them to be upgraded in the future.

Mr. Keen testified that an advanced metering infrastructure "AMI" requires a "smart meter" 1) which is capable of measuring and recording usage date in time-differentiated registers at intervals specified by either the utility or regulatory authorities, 2) allows electric consumers, supplies and service providers to participate in any number of price-demand response programs, and 3) provides data and other functionality which addresses power quality and other energy provision issues. Mr. Keen stated that these meters provide information to customers and encourages them to change energy uses, either in response to changes in price or through incentives designed to encourage lower energy usage at times of peak-demand periods, higher wholesale prices, or during periods of low operational systems reliability.

Mr. Keen testified that "smart meters" as a system offer increased functionality to both the consumer and the utility over the AMI system because smart meters offer real-time or near real-time sensors, power outage notification, and power quality monitoring capability and offer new functionality over AMI systems such as remote connect/disconnect, programming, and upgrade capabilities. He stated that Smart Meters function independent of the Smart Grid and may be part of a Smart Grid, but alone do not constitute a smart grid.

Mr. Keen testified that Distributed Generation, is a term now used to describe the generation of electricity from small-scale power generation technology to provide an alternative to or an enhancement of the traditional electric power system. He also testified that a Home Area Network or HAN is a network contained within a user's home to connect a person's digital devices to the network. Energy Management Enabled or "smart" appliances have an embedded chip able to communicate over a wired or wireless network to interface with a smart meter, controller or the utility company directly. Mr. Keen testified that the HAN allows multiple devices to cooperate with each other to fulfill the complex functionality of whole house energy management or can simply provide a means to deliver utility prices to home devices so they use energy when it is least expensive.

Mr. Keen testified that Plug-in Hybrid Vehicles (PHEVs) integrate into a smart grid when the vehicle is viewed as an energy storage device to offset peak demands. He said that "vehicle to grid" or V2G power can be best employed by a utility in relation to baseload and peak demand power consumption and it based on the concept that PHEVs are capable of providing power to assist in load balancing by "valley filling" and/or "peak shaving." Mr. Keen testified that the key to realizing economic value from V2G technology will be the precise timing of grid power production to correspond with consumer driving requirements while dovetailing with time-critical power "dispatch" requirements of the electric distribution system.

Mr. Keen testified that the OUCC supports open standards architecture because it ensures that Smart Grid technology deployed in Indiana will be upgradeable with future technology expansions and allows for the potential of increased consumption for manufacture and supply of components with better interoperability between different vendor devices. Mr. Keen testified that the OUCC commends those utilities which have made the commitment to deploy smart grid compatible technology and that if the Commission adopts the concept of mandating functionality rather than technology, electric utilities can incorporate the necessary technology in line with federal requirements to ensure the functionalities are available to the consumer.

According to Mr. Keen, the OUCC believes potentially the single greatest threat to any Smart Grid system may be its reliance on an IP-based system for information flow. Mr. Keen testified that the concept of remote attacks on systems which give an attacker the ability to control power production and distribution are no longer hypothetical events, but that the OUCC is aware of a number of initiatives which have been undertaken at the Federal level to mitigate the vulnerabilities of the Smart Grid. Mr. Keen testified that both the Commission and the public must always remember the Smart Grid and each of the individual components which make up the system are based on an IP-network infrastructure and can be "hacked."

Mr. Keen testified that many states have developed minimum functionality standards and other advanced metering policies to guide the deployment of Smart Grid technology in their states. Furthermore, Mr. Keen stated that on March 19, 2009, FERC released and requested comments regarding its "Proposed Policy Statement and Action Plan" outlining a national strategy for deployment of the smart grid system. Mr. Keen testified that the Commission should carefully and thoroughly examine the minimum requirement levied by each state thus far, while coordinating with those states which are still investigating AMI and smart grid technology deployment. This would allow Indiana to develop a set of minimum functional standards which dovetail with national standards and requirements as they become finalized.

Mr. Keen testified that the OUCC believes consumer education is important relative to the deployment of smart grid technology because consumers need to not only understand the concepts such as time-of-use rates and critical peak pricing, but also embrace new technology which is active in an intelligent grid. Educating the consumer would fall squarely on the back of each utility deploying the specific technology.

Mr. Keen testified that the Commission should not promulgate specific technology or software-architecture related standards, but should focus on function rather than specific technology. Focusing on functionality rather than technology ensures customers receive the types of services they expect regardless of the specific technology involved. Mr. Keen also testified that the OUCC believes the Commission should mandate all smart grid compatible technology deployed in Indiana should be based on open-standards architecture.

Mr. Andrew J. Satchwell, Utility Analyst in the Resource Planning, Emerging Technologies and Telecommunications Division of the OUCC, testified that the OUCC recommends the Commission: 1) develop a minimum set of costs and economic, reliability, and societal benefits in its consideration of smart grid investments; 2) develop a standard approach to cost-benefit analysis of smart grid investments, including, at a minimum, the matching of costs and benefits, development of a verification and accountability plan, and a reasonable balance of economic, reliability, and societal benefits, development of a verification and accountability plan, and a reasonable balance of economic, reliability, and societal benefits; and 3) consider the benefits of RTOs/ISOs in providing customer information.

Mr. Satchwell testified that smart grid investments are comprised of both capital and operation and maintenance (O&M) costs, with the three most common categories of capital costs being meters, networks/communications and installation. He testified that costs will vary greatly by utility based upon the technology, communication system, and smart grid system components chosen in the business case. Mr. Satchwell testified that cost components should be consistent among smart grid business cases.

According to Mr. Satchwell, there are three distinct categories of smart grid investments: economic, reliability and societal benefits. Mr. Satchwell testified that economic benefits are those that accrue to the utility and ratepayers through a direct reduction in expenses. Reliability benefits are those that accrue to the utility system, mostly as a result of improvements to the distribution service. Societal benefits are those that accrue to non-participating and/or non-utility stakeholders.

Mr. Satchwell also testified that the smart grid can more efficiently and effectively communicate time-based price signals than the current grid system, which enables customers to make energy consumption decisions based on prices. He said that smart grid meter investments enable more precise interval measurements of usage and integrate a two-way communication to better inform customers of real-time usage.

Mr. Satchwell testified that while expected costs can be easily quantified based on actual vendor responses to requests for proposals, benefits can be more difficult to quantify, especially when considering societal benefits and other prospective benefits. He testified that quantifying benefits relies on prospective assumptions that may input error into any cost-benefit model, which is intended to justify a smart grid business plan.

According to Mr. Satchwell, not all benefits accrue to ratepayers and treating all benefits the same fails to recognize that some benefits accrue only to the utility whereas other benefits accrue only to the ratepayers. He recommended that the Commission adopt a consistent approach to cost-benefit modeling of smart grid investments. That approach should include at a minimum; the matching of costs and benefits, development of verification and accountability plan, and a reasonable balance of economic, reliability, and societal benefits. Mr. Satchwell testified that any cost-benefit analysis should ensure that each benefit to be enjoyed by ratepayers should be matched with any cost to create that benefit. According to Mr. Satchwell, a plan for accountability of cost-benefit analysis results is necessary to verify the savings being delivered to ratepayers, which should be built on the Oversight Boards, measurement and verification standards, and true-up mechanisms present in Indiana electric and gas utility Energy Efficiency programs. Mr. Satchwell testified that any smart grid investment should stand on its own merits based on known, easy-to-measure and verifiable benefits.

Mr. Satchwell testified that the Midwest ISO has not begun a formal stakeholder process to address the smart grid at the RTO/ISO level. PJM has, however, initiated a Smart Grid Working Group within its Transmission Owner's stakeholder group to develop a cohesive approach to the development of a smart grid. Mr. Satchwell testified that he recommends the Commission consider the benefit of RTOs/ISOs in providing transmission system information and wholesale market pricing information to utilities and customers. According to Mr. Satchwell, accurate wholesale price information is vital in developing and providing dynamic pricing options.

Mr. Greg A. Foster, Utility Analyst in the Electric Division of the OUCC Energy Group, testified that utilities should use a more traditional regulatory treatment instead of an accelerated cost recovery mechanism for smart grid projects. According to him, other options could include periodic rate case proceedings, deferred depreciation, and/or post in-service allowance for funds used during construction (AFUDC). Mr. Foster testified that utilities are generally allowed to accrue AFUDC to reflect financing costs associated with construction work in progress and once a project is complete and put in service, the project's accumulated costs are placed into rate base, depreciation begins, and the utility would begin receiving revenue. However, the utility's revenues would not reflect this additional revenue stream until the utility had a base rate case where the Order recognizes the inclusion of the construction costs of the project in rate base. Mr. Foster testified that utilities could bridge the gap between the time the project is completed and the time the Commission issues an order in its next base rate case proceeding by filing a petition with the Commission asking it be granted post-in-service AFUDC and deferred depreciation on smart grid investments. According to Mr. Foster, the Commission has granted these types of requests in the past.

Mr. Foster testified that a "smart grid" is a culmination of individual "smart" parts. According to him, a smart grid, or advanced metering infrastructure (AMI), is an automated, intelligent delivery system that uses computer-based technologies to help electric utilities find more cost-effective ways to run their operations. Mr. Foster testified that through the use of the two-way communications systems and other advanced operation tools that smart grids provide, utilities have the ability to boost reliability, improve efficiency, reduce power consumption, especially at peak demand times, and help customers lower their electric bills.

Mr. Foster testified that guidelines for cost recovery have not yet been established. He testified that, in February 2008, the National Association of Regulatory Utility Commissions (NARUC) named 16 regulatory commissioners to serve in a joint federal-state collaborative effort focused on facilitating the transition to a smart grid. He also testified that, on March 19, 2009, the Federal Energy Regulatory Commission (FERC) filed a Proposed Policy Statement and Action Plan as to a Smart Grid. Mr. Foster testified that the FERC recognized that a key consideration of public utilities in deciding whether to invest in Smart Grid technologies may involve the potential for stranded costs associated with legacy systems. To offer some rate certainty and guidance regarding cost recovery issues, the FERC is proposing a rate policy for the interim period until final interoperability standards are adopted. He said that the OUCC understand the utilities' concern regarding cost recovery issues and, after a more thorough review of FERC's Proposed Policy Statement and Action Plan, the OUCC looks forward to working collaboratively with Indiana utilities to address concerns over cost recovery.

According to Mr. Foster, the OUCC believes that all customers at all usage levels should bear part of the costs associated with deploying smart meters and retiring less sophisticated meters. The cost allocation issues would be resolved as part of the examination of the cost of service study and rate design. Mr. Foster testified that customers should be able to reduce energy consumption and costs in response to usage and pricing information provided in real-time. Mr. Foster stated that any reduction in demand during peak hours helps the utility lower its overall power costs by reducing the amount of purchased power that the company needs to buy to serve load or possibly preclude the use of peak generation. And, according to Mr. Foster, since fuel costs and costs associated with purchased power are ultimately passed on to ratepayers, all customers benefit from a reduction in purchased power as the company's overall cost of power decreases.

Mr. Foster testified that the ARRA contains $4.5 billion in matching funds allocated to "Electricity Delivery and Energy Reliability," by which applicants can obtain grants of not more than one-half of their documented costs. Mr. Foster testified that details of the matching program had not been established, but on March 30, 2009, the NARUC/FERC Smart Grid Collaborative filed with the DOE proposed funding criteria for the ARRA Smart Grid Matching Grant Program and the ARRA Smart Grid Demonstration Projects.

E. Industrial Group. Nicholas Phillips, Jr., a consultant in the field of public utility regulation and a principal with the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants, testified on behalf of the Industrial Group. Mr. Phillips testified that he does not oppose prudent Smart Grid expenditures or any other prudent distribution system expenditures by Indiana utilities and that the utilities should continuously evaluate opportunities to improve their systems. According to Mr. Phillips, if smart grid investments are cost-effective, utilities should not need further incentive or encouragement to pursue such investments. Mr. Phillips testified that if utilities seek to use Smart Grid investments as a basis for new trackers, that would constitute single issue ratemaking and is not appropriate.

Mr. Phillips testified that smart grid investments are expected to open up a great deal of information regarding how customers, particularly small customers, use electricity that is not readily available today. He said that to the extent utility regulation is intended to be a surrogate for competition, utilities should not require cost recovery mechanisms which would not be employed in the market.

According to Mr. Phillips, meter investments are not a utility-only function. Mr. Phillips testified that the Commission should proceed with caution in approving any standard which expands monopoly power and/or special cost recovery mechanisms into a function which is not solely a utility function. Mr. Phillips said that rate base is largely a function of net plant, which is based on utility plant in service less accumulated depreciation. He said it is important to recognize that rate base does not automatically increase with additional investment in plant, and a revenue deficiency doesn't automatically occur with annual utility investment. This is particularly true, in his view, with regard to smart grid investment which also provides the opportunity for a utility to lower operating expenses.

Mr. Phillips testified that he is concerned that trackers reduce the risk to the utility and under a tracker formula, utility shareholders assume no risk for the proposed smart grid investments. He testified that if smart grid investments impact a utility's ability to earn a fair return, the utility is able to file a rate case to address the situation. Furthermore, smart grid investments should provide additional information regarding customer usage and a rate case provides the opportunity for a utility to utilize that information in designing new rates.

Mr. Phillips testified that, based on the information available and the ability of the Commission to undertake the standard's activities in a base rate case, the adoption of the smart grid investments standard in Section 111 (D) (18) in the EISA is not required at this time. He recommended that the Commission should not proceed with a cost-recovery program when the parameters surrounding costs, benefits and relevant details associated with Smart Grid investments are unknown and that experience from current or planned pilot programs would provide useful and necessary information. Mr. Phillips testified that, if the Commission chooses to adopt the standards, it can carry out the prescribed activities in a utility rate case. Mr. Phillips also testified that he is not expressing an opinion as to whether or not the Commission should adopt the standards in Section 111 (D) (19) of the EISA at this time.

F. Wal-Mart. Ken Baker, Senior Manager for Sustainable Regulation testified on behalf of Wal-Mart Mr. Baker testified that Wal-Mart is a large commercial customer in Indiana with 84 Supercenters, 15 Discount Stores, 4 Neighborhood Markets, 17 Sam's Clubs and 6 Distribution Centers. He testified that Wal-Mart has made an operational and financial commitment to environmental stewardship in many aspects of its business. Mr. Baker testified that, since 2005, Wal-Mart has installed over 1,185 advanced meters in its U.S. stores, including eighteen advanced meters in Indiana and that these meters are a major driver in Wal-Mart's ability to have a substantial impact on peak load reduction when called upon by the utility/ISO during times of peak usage. Furthermore, the advanced metering system has helped Wal-Mart with its effort to reduce its energy consumption, which yields secondary benefits, such as reduction of congestion on the grid. Based on Wal-Mart's experiences, Mr. Baker testified that the Commission should require utilities that are planning "nonadvanced investments" to consider smart grid investments. Mr. Baker also testified that Wal-Mart asks the Commission to ensure that ratepayers are the direct beneficiaries of any standard.

Mr. Baker testified that, from a customer perspective, the expected direct benefits to be derived from Smart Grid investments are reduced energy usage and the increased ability of customers to manage their own energy loads. He said that if the Commission does not require utilities to consider smart grid investments, it should ensure a variety of pricing options are made available to customers as part of any smart grid plan. Utilities making smart grid investments should work collaboratively with customers to formulate a menu of pricing options that provide opportunities for all customers to optimize energy use and demand reductions.

Mr. Baker testified that smart grid investments should result in customers knowing how much electricity they are using at any given time and the cost of that electricity. He said that, to the extent that customers have made technical and capital investments in advanced meters on their own, meter replacement should not be required under a utility's smart grid plan, so long as the customer's meters are interoperable with the utility's system.

Steve W. Chriss, Manager, State Rate Proceedings, testified on behalf of Wal-Mart. Mr. Chriss testified that Wal-Mart generally does not oppose the adoption of Section 18 (B) of the EISA, but that the Commission should not adopt Section 19 from the perspective of provision of pricing information. Mr. Chriss testified that the Commission should require utilities to provide the type and amount of information commensurate with the pricing structure implemented as part of a smart grid roll-out.

Mr. Chriss testified that Wal-Mart does not oppose the recovery through rates of utility costs determined by the Commission to be prudent. He said that the appropriate forum for consideration of costs related to smart grid implementation is a general rate case. Mr. Chriss testified that single-issue ratemaking between or separate from general rate cases may not involve adjustments to rate of return components, and such adjustments are sometimes required to appropriately reflect the reduction in risk experienced by the utility. He also said that the Commission should consider the extent to which smart grid implementation costs are volatile or not able to be controlled by the utility, which are traditional reasons to allow rider-based cost recovery of certain utility costs such as fuel. Mr. Chriss testified that it is appropriate to determine the recovery of smart grid costs in the framework of a full cost of service study. He said that the rate transparency and the implementation of time based rates are integral parts of a smart grid roll-out.

Mr. Chriss testified that time based rates are the key to achieving the operational benefits of smart grid investments and that the tools are proposed to give customers the ability to recognize and respond to the price signals already inherent in utilities' system operations. Mr. Chriss testified that there should be a variety of information available to customers because not all customers may benefit from the same types of information and cost in relation to value should be a consideration in determining what data should be made available. Furthermore, different rate structures will require different levels of information provided to customers. Mr. Chriss testified that continuous and reliable provision of wholesale prices would provide negligible benefit, versus the cost of implementation, to customers under a time of use rate structure.

Mr. Chriss testified that the Commission should not adopt the EISA Section 19 standards because the standards fail to consider the type and amount of pricing information required will vary with the pricing option chosen. He said that the Commission should require utilities to provide the type and amount of information commensurate with the implemented pricing structure. Mr. Chriss argues that it is important to consider that rates should be set to reflect the utility's cost of service. Wal-Mart advocates that rates be set based on the utility's cost of service in order to provide equitable rates that reflect cost causation and minimize price distortions. Mr. Chriss testified that setting rates at cost of service can also address the issue of reduced fixed cost recovery due to price-responsive load curtailments. The rate-setting process for smart grid implementation should consider rate structures that incorporate straight-fixes variable concepts, in which a utility's fixed and variable costs are charged on bases reflective of the manner in which they are incurred.

G. <u>ITA</u>. Mr. Alan J. Matsumoto, Regulatory Manager for Embarq Corporation testified on behalf of the ITA. Mr. Matsumoto testified that there are competitive safeguards for the communications services that utilities may provide to protect against anti-competitive behavior. According to him, these safeguards would help ensure that ratepayers and consumers of regulated energy services are not subsidizing or otherwise supporting the communications offerings of energy utilities.

Mr. Matsumoto testified that recovery of the investments and expenses associated with communications services through rates or riders charged to captive energy customers would be inequitable to those customers and result in their subsidizing the telecommunications offerings of their energy utility. He testified that if the investments and expenses for communications services are not appropriately identified and recovered, customers with no desire or intention to purchase any communications services, would effectively subsidize the subscribers of those services and the cross-subsidies that could be created would also lead to inappropriate pricing signals to the communications market.

Mr. Matsumoto testified that one alternative is for energy utilities to divest ownership and interests in their communications operations into a separate, independent corporate entity. Another option, in his view, is a functional separation where the communications operations of an energy utility are placed in a separate division from its retail electric operations and the divisions operate with an arms-length relationship. Finally, he testified, that energy utilities could maintain separate books, records and accounts for its communications services and develop a cost allocation methodology.

4. **Responsive Testimony.**

A. **Utility Group – Joint Testimony.** On May 7, 2009, the Utility Group collectively submitted their joint responsive testimony as Joint Exhibit 2. The Utility Group noted that overall the parties appear to be in consensus that Indiana's current statutory scheme provides the Commission with sufficient authority to consider Smart Grid investments without the need to formally adopt the federal standards contained within the EISA.

The Utility Group noted that the OUCC did not specifically address whether the Commission should adopt the federal standards, but did emphasize the need to be flexible in setting Smart Grid standards. The Utility Group further noted that while Wal-Mart indicated that it "generally does not oppose the adoption of Section 18(B)," Wal-Mart did oppose adoption of Section 19's pricing information standards. The Utility Group suggested there was widespread agreement that flexibility is needed in this context and that any attempts to adopt "mandatory" requirements might inhibit the optimal development and deployment of Smart Grid technology. The Utility Group concluded that it seems clear that Indiana's existing regulatory framework allows for consideration of the federal standards contained within EISA and thus it is not appropriate or necessary to formally adopt the federal standards contained in Sections 111(d)(18)-(19) of PURPA.

With regard to state consideration of Smart Grid investments (PURPA Section 111(d)(18)), the Utility Group disagreed with the recommendations of OUCC witness Satchwell. Mr. Satchwell recommended that the Commission adopt a consistent approach to cost-benefit modeling of smart grid investments, which would include at a minimum the matching of costs and benefits, development of a verification and accountability plan, and a reasonable balance of economic, reliability, and societal benefits. The Utility Group responded that because each utility has a unique customer base and infrastructure, it would be difficult to model a consistent cost-benefit approach to Smart Grid investments. As an alternative to Mr. Satchwell's approach, the Utility Group suggested that the Commission should consider "core functions" for Smart Grid implementations and cost recovery. The Utility Group suggested that this approach would be more appropriate than a specific cost-benefit model because many aspects of a unique utility's operations should be considered, and these vary with each utility. In addition, there is a need for the Commission to permit a dynamic approach to the analysis for individual utilities because long-term plans are different for each utility and because the technology is constantly evolving. Finally, the Utility Group stated that the Commission can review the utility's analysis as part of approving cost recovery, but a standard approach may hamper a utility's ability to make its best case.

Mr. Satchwell testified that some Smart Grid benefits accrue only to the utility and other benefits accrue only to ratepayers, and therefore all Smart Grid benefits should not be treated the same. The Utility Group gave two reasons why it disagreed with Mr. Satchwell's position. First, by suggesting that benefits should not all be treated the same, Mr. Satchwell overlooks the fact that many of the benefits of Smart Grid technologies are intangible and difficult to quantify. Subjective attempts to parse Smart Grid benefits and then allocate them among different stakeholders could also lead to an attempt to assign cost responsibility related to those benefits. Given the interrelated benefits that will be enjoyed by all stakeholders from the implementation of Smart Grid, the Utility Group stated that such an approach could result in division among stakeholders engaged in a piecemeal review of projects, versus a focus on larger, long term benefits and goals and broad support for investment in a system that will provide benefits for all. Second, the Utility Group disagreed with Mr. Satchwell's assertion that "some benefits accrue only to the utility." The Utility Group stated that in the long run, all benefits that accrue to a utility will also benefit the utility's customers. The Utility Group concluded that while it might be useful to identify the wide range of benefits that will flow from implementation of a Smart Grid system, and it would also be helpful to know which stakeholders will enjoy each of the listed benefits, it would be counterproductive to use this information to create a "balance sheet" for each stakeholder.

The Utility Group disagreed with Mr. Satchwell's statement that a plan for accountability of cost-benefit analysis results is necessary to verify that savings are being delivered to ratepayers. Mr. Satchwell went on to suggest that Oversight Boards, measurement and verifications standards, and true-up mechanisms should be implemented to accomplish this. The Utility Group responded that if, in order to achieve broader societal goals, it is necessary for a utility to invest in expensive "smart" equipment rather than less expensive non-advanced equipment, such an investment should not be viewed as some sort of "promise" by the utility that the benefits associated with the more expensive equipment will materialize. From the Utility Group's perspective, if a piece of equipment is used and useful, it should be included in rate base.

The Utility Group noted that decisions to implement Smart Grid technologies will require utilities, on the front-end of the decision process, to outline the costs and the benefits that will likely attend a proposed investment. Thus, the Utility Group agreed that review of programs is appropriate. However, the Utility Group stated it did not believe Oversight Boards are necessary, and requiring their use would present an element of uncertainty to the process and may hinder the efficient consideration of technology and programs for each utility. Instead, the Utility Group stated that the review of programs can come through the traditional regulatory process, or those used in specific environments such as progress reports in pollution control equipment certificate proceedings. The Utility Group stated that utilities should be given the ability to address their infrastructure needs in the way that best meets their business requirements and those of their customers. There should be no hindsight review that second-guesses the efficacy of the new equipment, or the level of benefits that have resulted. The Utility Group has already expressed its willingness to apprise the Commission of each of the utility's future plans with regard to deployment of new Smart Grid technologies. If a utility chooses a pre-approval process for those technologies, then there should be no hindsight "accountability" review; rather, the process should provide for the ability to evaluate and make changes to prospective initiatives. Finally, the Utility Group noted there are practical problems with "accountability" and the "verification of savings" suggested by Mr. Satchwell. Given the intangible nature of the benefits that will result from the integration of multiple technologies, attempts to quantify all benefits and assign those benefits to particular costs would be difficult and subjective. Moreover, due to the complexity and high cost of transitioning to a Smart Grid, the Utility Group stated it is not realistic to expect a sudden transition from old to new. Rather, there will likely be a slow metamorphosis as older systems are replaced by newer systems. This slow transition will impair attempts to isolate and attribute "savings" to discrete investments in new infrastructure.

With regard to cost recovery for Smart Grid investments, the Utility Group noted that an investment in Smart Grid infrastructure can be substantial -- comparable to the addition of a small generating plant or a significant pollution control project. Without a reasonable opportunity to recover the costs of Smart Grid investments on a timely basis, an investing utility's earnings and cash flow will be adversely impacted. Since many utilities are considering some type of investment in Smart Grid technology, the Utility Group stated this potential earnings erosion could take place at a time when maintaining a good credit rating is more important than it has been in the recent past. The Utility Group further noted that, unlike certain other utility investments, investments in Smart Grid technology - e.g., smart meters, distribution and transmission line equipment, etc., will likely involve numerous investments over an extended deployment period. The Utility Group pointed out that because this equipment goes into service almost immediately, unlike larger construction projects, there is simply no way to time a general rate case (or cases) to recover investments in Smart Grid technology without the utility suffering material earnings and cash flow erosion in the process, to the potential detriment of its credit quality.

The Utility Group stated that with regard to recovery of Smart Grid investments, deferred accounting treatment by itself would not be sufficient to protect the financial situation of utilities making Smart Grid investments. Although deferred accounting can be a useful tool for dealing with significant investments between rate cases, the Utility Group stated that deferred accounting does not provide current cash flows to support cash needs during the time a utility is spending the cash to make system improvements. In addition, the Utility Group noted that GAAP accounting rules do not allow a utility to recognize in current income the equity component of the return for financial reporting purposes, such that even with deferred accounting, a utility will suffer earnings erosion compared to more timely recovery. In addition, the Utility Group noted that allowing a utility to timely recover its investments in Smart Grid technology will result in more gradual and smoother increases in rates as opposed to increases that can occur with general rate cases. Depending on the timing of the next general rate case, deferred accounting treatment will only add to the rate change at that time as the additional post-in-service carrying costs and deferred depreciation are included in rates.

The Utility Group expressed its opinion that special ratemaking treatment is better suited to recovery of Smart Grid investments than is a general rate case. In support, the Utility Group stated that general rate cases are time-consuming and costly. They are normally based on historical costs for a pro forma test year, such that once new rates are approved, they are already "out of date," and in an increasing cost environment (such as we are in today), the utility effectively cannot ever earn its authorized return or recover its approved revenue requirements. Moreover, given the test year and cut-off date conventions of general rate cases, as well as Indiana's "anti-pancaking" "15-month" rule, the Utility Group stated that rate cases cannot really accommodate staggered investments such as those in Smart Grid equipment. Unlike a generating plant, or a new office building, which goes into service on a single day, Smart Grid investments would more likely be placed into service on a continually staggered basis. The Industrial Group observed that Smart Grid investments present ratemaking and cost recovery challenges similar to an environmental compliance plan that consists of multiple, staggered investments. In addition, since allocation of costs is generally a contentious issue, the Industrial Group suggested that appropriate Smart Grid costs in a tracking proceeding can be allocated based upon the cost allocators approved in the utility's last general rate proceeding, thereby reducing the issues to be considered in a cost-recovery proceeding designed to facilitate the timely recovery of Smart Grid investments.

Finally, with regard to cost recovery, the Utility Group explained why timely recovery for Smart Grid investments represents good regulatory policy. First, timely recovery will give an investing company the opportunity to recover its reasonable and prudent costs of providing service to customers on a more timely basis, and will afford that company more of a real opportunity to earn its authorized return. In addition, smaller, predictable annual rate increases are likely to be more manageable for customers than larger base rate increases. Moreover, a more timely recovery of prudent and reasonable costs will permit an investing company's rates to more precisely reflect the true cost of providing utility service to customers. Finally, when a utility has an opportunity to recover its reasonable and prudent costs of providing utility service that sends positive signals to the financial markets that will bolster support of the investing company's credit quality, which is important given the magnitude of financing needs each utility likely faces for environmental compliance, new generation, and other system improvements. The Utility Group intimated that capital is finite, and as a utility prioritizes projects to meet the needs of its customers and responds to new environmental requirements, those projects and policies that received support will be pursued. In addition, timely cost recovery also encourages on-going deployment, which among other customer benefits, promotes greater system reliability.

Turning to the issues raised by the ITA, the Utility Group disagreed with the ITA's recommendations for "competitive safeguards" such as functional or corporate separation of a utility's communications-related equipment, maintenance of separate books and records, and development of cost allocation procedures. Before addressing the substance of the ITA's suggestion, the Utility Group pointed out that the Commission made clear that the scope of this docket was to consider adoption of identified federal standards, and there was no utility specific technology proposal before the Commission in this proceeding. The Utility Group stated that the responding electric utilities do not propose in this docket to use smart grid equipment to offer "communications services" (as defined by Indiana statute). The Utility Group concluded that Mr. Matsumoto is addressing a hypothetical possibility that does not presently exist, and for that reason it makes no sense to spend the time, effort and expense now to try and address a situation that may never develop. With regard to the substance of the ITA's recommendations, in the view of the Utility Group, the "safeguards" proposed by ITA were totally unnecessary. The Utility Group pointed out that if a regulated electric utility should elect to engage in communications service, cost of service based regulation of retail electric service prevents the potential for cross-subsidies that concerns Mr. Matsumoto. The Utility Group further explained that because retail electric service rates are regulated, a cost of service study would separate jurisdictions and different services to ensure that retail electric rates only reflect costs for providing retail electric service. As a result, an electric utility seeking to provide communications service as defined in IC 8-1-32.6-1 will necessarily need to recoup the costs of doing so through the prices of its communications service offerings. The Industrial Group stated there are several instances where regulation already prevents the type of potential cross-subsidization that troubles Mr. Matsumoto, and provided an example of a combined electric and gas utility which must allocate costs to electric and gas services and retail and wholesale jurisdictions.

The Utility Group's final point with regard to the ITA's position is that there is the potential for harm to the future implementation of smart grid technology if the ITA's interests are considered at this early stage in the study of these technologies. In considering the cost and benefits of Smart Grid applications, utilities will look for ways to cost effectively enhance service to their customers, which may include the ability to communicate with customers regarding energy consumption and market prices. The Industrial Group stated that how this communication occurs may vary depending on the nature of existing facilities, choices made in future technology applications, service territory demographics, etc. Rather than try to foresee how this may occur throughout the State and establish standard rules now, the Utility Group recommended that utilities should be able to learn from other projects, study alternatives, and then come to the Commission with proposals where customer interests, costs, timing, and the public interest can be considered, as well as the views of the ITA. The Utility Group explained that trying to solve an alleged problem before it exists can lead to unforeseen consequences that slow innovation, limit otherwise viable alternatives and increase costs.

In summary, the Utility Group stated that EISA does not mandate that the Commission adopt the Smart Grid standards. Like other PURPA standards, the Commission is required to consider the standards, but it retains the discretion to adopt or reject the proposed standards. The Utility Group stated that it believes adoption of the EISA standards is unnecessary because the Commission presently possesses sufficient authority under existing statutes and regulations to ensure that energy efficiency resources are considered and timely cost recovery provided. The Utility Group pointed out that Indiana utilities have already begun to study and undertake measures similar to Smart Grid on their own as a means to conserve energy, optimize efficiency and use of resources, and maintain equitable rates for consumers. Since the purposes of EISA are already being advanced, the Utility Group stated the Commission does not need to adopt the proposed standards. However, due to the large investments in advanced technologies that are required in order for Indiana electric consumers to benefit from a Smart Grid system, the Utility Group stressed that utilities will need to be assured of their ability to earn a return on and to recover their investments in a timely manner, including any remaining investment in facilities rendered obsolete as a result of the utility's Smart Grid investments. Thus, while it is unnecessary for the Commission to adopt the proposed standards, the Commission should permit utilities to timely recover the costs associated with Smart Grid technologies.

B. <u>OUCC</u>. Mr. Keen testified that the OUCC continues to be convinced that technology does exist today to deploy a fully functional smart grid and that some utilities may be in a position to deploy a true smart grid, but the OUCC remains cognizant that the costs and planning required to deploy even portions of a fully functional smart grid are significant and complex. He testified that the OUCC believes it may be prudent and wise for utilities deploying smart grid technology to proceed in a phased approach-upgrading existing systems and deploying new smart grid compatible technology as financing and capability exist. He testified that each utility must first develop a "master" strategy to reach the end goal of developing a fully-functional smart grid, and then work to achieve that goal through a series of phases to test, evaluate, and operationally deploy segments of the technology.

Mr. Keen testified that a timeline should be considered a guide, but it does afford a benefit to consumers by offering a reference point of when they can expect to take full advantage of the benefits that a fully-functional smart grid will offer. He also testified that the OUCC believes a state-wide vision on what constitutes a Qualified Smart Grid System is needed to allow other issues to be addressed. The Commission should establish only the minimum functionality standards required for deploying of a fully functional smart grid throughout the state.

Mr. Keen testified that the single caveat the OUCC would place on leaving the technology aspect up to the utility would be that all technology should be based on open-standards architecture. Mr. Keen testified that this open-standards architecture ensures smart grid technology will be upgradable with future technology expansions and allow for the potential of increased competition for manufacture and supply of components with better interoperability between different vendor devices. Mr. Keen testified that the first eight "requirements" of the EISA, Title XIIII, Section 1301 offer a clear set of minimum functionality standards which could be used to define a fully functional "smart grid" in Indiana.

Mr. Keen testified that, while the OUCC is aware of the issues regarding cross-subsidization of non-regulated services with regulated revenues, the agency supports the entrance of additional communications service providers into Indiana's communication market to ensure the best service offerings, technology and prices for Indiana consumers. He stated that the mere existence of infrastructure deployed solely to support grid operations should not be construed to imply a capability or even the expressed desire by the energy utility to provision communication services to consumers until such time as the energy utility formally applies to the Commission for a Certificate of Territorial Authority to operate as a Communications Service Provider within the State of Indiana. Mr. Keen testified that the Indiana Telecommunications Association's concerns are premature at the current time.

Mr. Satchwell testified that the identification of a minimum set of smart grid costs and benefits would aid in defining the vision of the smart grid in Indiana. He testified that the Utility Group's testimony, as well as that filed by Vectren Witness Sears and Duke Energy Indiana Witness Arnold illustrates the current consideration of smart grid costs and benefits and supports his recommendation that societal benefits be included in the minimum set of benefits considered by the Commission.

Mr. Satchwell testified that the specific Indiana Investor-owned utility witnesses have provided very little in terms of time-based pricing offerings to retail customers, thereby denying customers certain economic benefits. Mr. Satchwell testified that the Utility Group's additional suggestions to incorporate the results of Indiana smart grid deployments with the DOE Smart Grid Clearinghouse is worthwhile because shared experiences and information can reduce costs to consumers and expedites the implementation of smart grid technologies. He testified that a consistent approach to cost-benefit analysis determined by the Commission would better direct those efforts by third-party consultants and yield analyses which can be more easily interpreted by all parties.

Mr. Satchwell testified that access to wholesale price information could be used to develop dynamic pricing options with more accurate price signals. Those price signals would be more accurate with the blending of wholesale, RTO power prices because it would reflect the regional, wholesale costs incurred by a utility.

Mr. Foster testified that even a fully-developed smart grid vision must be viewed in the context of the specific utility's smart grid plan when conducting cost-benefit analyses and deciding cost recovery issues. He testified that a fully developed vision would identify and incorporate ways for consumers to benefit from new meter-based modes of communication, maximizing cost savings opportunities for both the utility and its customers. Mr. Foster testified that consideration of advance commitments requires determination of which risks may be shifted between a utility's shareholders and its customers, and the benefits provided in response to any approved risk-shifting. He testified that modifications to the traditional approach to cost recovery could unreasonably shift risk from shareholders to ratepayers if not limited. To Mr. Foster, those concerns raised the issue of whether the Commission should reduce the utility's authorized Return on Equity in response to the decreased business and financial risks associated with advance cost recovery mechanisms. Mr. Foster testified that the Commission should consider such concerns when reviewing specific utility requests for guaranteed advance cost recovery.

Mr. Foster testified that the Commission should allow the OUCC to work collaboratively with individual utilities to identify and recommend to the Commission a specific method of cost recovery that makes the most sense for a particular utility, based on the utility's specific smart grid plans.

C. **Industrial Group**. Mr. Phillips testified that a policy that permits a utility to adjust its rates for individual cost or revenue items outside of a base rate case shifts regulatory risk from utility investors to customers by providing investors with accelerated recognition of specific cost and revenue adjustments in utility rates. A utility's allowed return on rate base is established to compensate the utility's investors for the various business risks it incurs, among them the risk that regulatory lag will delay the recognition of cost increases or revenue fluctuations in utility rates between base rate cases.

Mr. Phillips testified that deferring expenses until a rate case presents many of the same problems as a tracker to recover the same costs. Risk is still shifted from shareholders to ratepayers. Mr. Phillips testified that if the OUCC is suggesting that meter investment be allocated to a class other than that which receives the new meter, such a policy should be rejected. Meter upgrades are customer-related costs, and meters for one class should not be allocated to other classes.

D. **Wal-Mart.** Mr. Baker testified that utilities should take advantage of existing and future customer investments in meters and should rely more heavily on customer, rather than ratepayer, funded equipment, which could minimize costs for all customers. Mr. Baker testified that customers that make substantial investments in energy efficiency by installing energy management systems should not be constrained by other entities' requirements for behind-the-meter equipment. The Commission should encourage utilities to seek Smart Grid solutions that not only do not require redundant investments by the customer, on its own and as a ratepayer, but take advantage of customer investment.

5. Discussion and Findings.

A. EISA Standards. As stated in the Commission's October 8, 2009 Order and the February 10, 2009 docket entry (February 10th Docket Entry) in this Cause, the Commission initiated "this proceeding to commence its consideration of Smart Grid Investments and Smart Grid Information contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)), as amended by the Energy Independence and Security Act of 2007." Like other PURPA standards, the Commission is required to consider the standards but retains the discretion to adopt or reject the proposed standards.

The February 10th Docket Entry included a list of issues that the Commission recognized as related to the adoption of the suggested standards and not as a critique on the Smart Grid concept. These issues were discussed at an informal technical conference conducted on February 19, 2009 and were also addressed in the testimony presented by the parties in this Cause. The February 10th Docket Entry also established that the "consideration of the standards presented in EISA is a significantly narrower focus than an exploration of the broad concept of a Smart Grid" and this proceeding "should be generally limited to the appropriateness of adopting the suggested standards."

The two standards we must consider are: (1) Consideration of Smart Grid Investments (PURPA Section 111(d)(18)); and (2) Smart Grid Information (PURPA Section 111(d)(19)). More particularly, we must consider whether adoption of these standards is appropriate in order to promote (1) conservation of energy supplied by electric utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers.

Substantial record evidence and our review of the law and regulations demonstrate that the Commission presently possesses sufficient authority under existing statutes and regulations to ensure that energy efficiency resources are considered and timely cost recovery provided. Indiana utilities have already begun to undertake measures similar to Smart Grid on their own as a means to conserve energy, optimize efficiency and use of resources, and maintain equitable rates for consumers. Thus, we find that Indiana's current statutory scheme provides the Commission with sufficient authority to consider Smart Grid investments without the need to formally adopt the federal standards contained within the EISA. Flexibility is needed in this context and any attempts to adopt "mandatory" requirements might inhibit the optimal development and deployment of Smart Grid technology. We conclude it is unnecessary at this time to adopt the PURPA standards contained in Sections 111(d)(18)(A) and 111(d)(19).

We must also consider in this proceeding cost recovery relating to the deployment of a qualified smart grid system, including a reasonable rate of return, and timely recovery of remaining book-value costs of any equipment rendered obsolete by a smart grid deployment pursuant to Section 111(d)(18)(B)-(C). It is clear from the evidence presented in this proceeding that investments in smart grid infrastructure can be substantial and will most likely involve an extended deployment period. The evidence presented has also highlighted the importance of encouraging investments in smart grid technologies, both in order for Indiana utilities to take advantage of ARRA funding, and for Indiana to begin to see the benefits of a smart grid anticipated to accrue to utilities, customers, and the State. Our discussion therefore shifts to reviewing the options available for utilities to recover smart grid investments.

Although a number of parties argued that tracker recovery was unnecessary for smart grid investments, the OUCC did recognize that special accounting authority might be required to support large investments in Smart Grid technologies. The Utility Group presented testimony describing why tracker recovery is particularly appropriate for investments in smart grid and why deferral accounting treatment by itself is inadequate. The Utility Group stated that deferral accounting can be a useful tool for dealing with significant investments between rate cases, but does not provide current cash flows to support cash needs during the time a utility is spending the cash to make system improvements. Further, more timely recovery of smart grid costs would result in more gradual and smoother increases in rates, as opposed to increases that can occur with deferred accounting treatment and general rate cases. The Utility Group also noted that unlike a generating plant, which goes into service on a single day, smart grid investments would more likely be placed into service on a continually staggered basis. This presents similar ratemaking and cost recovery challenges to an environmental compliance plan consisting of ongoing large staggered investments.

In contrast, several parties advocated for recovery of smart grid investment through base rate cases, where the Commission would have the opportunity to review all costs, benefits, and risks in a comprehensive manner. The Industrial Group puts forth the reasonable suggestion that utilities should continuously evaluate opportunities to improve their systems and if smart grid investments are cost-effective, utilities should not need further incentive or encouragement to pursue such investments. We find this concept strongly in-line with the standard understanding of the regulatory compact.

While the Commission recognizes timely cost recovery can encourage smart grid investments, we note that "timely" is not well-defined in the federal standards contained in Section 111. Further, as we noted above, the record evidence and our review of the law and regulations demonstrate that the Commission presently possesses sufficient authority under existing statutes and regulations to consider various means of timely cost recovery. We conclude it is unnecessary at this time to adopt the PURPA standards contained in Sections 111(d)(18)(B)-(C). Specific smart grid investments and the applicable cost recovery proposals related thereto will be considered in the course of utility-specific proceedings.

Accordingly, the Commission finds that upon consideration of the evidence submitted, it is not appropriate or necessary to formally adopt the proposed federal standards contained in Sections 111(d)(18)-(19) of PURPA.

B. <u>ITA Issues</u>. The ITA made certain recommendations for "competitive safeguards" in its testimony in this proceeding. We agree with the Utility Group that it is unnecessary at this time to consider the ITA's recommendation as part of this proceeding. Any party seeking to provide communications services within Indiana is required to obtain a certificate of territorial authority to provide those services, and such a filing would provide any intervenors the opportunity to participate in that proceeding. Attempting to address such a potential issue before it arises could lead to unforeseen consequences that slow innovation, limit otherwise viable alternatives, and increase costs. Accordingly, the Commission declines to adopt the proposed standards suggested by the ITA.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Commission hereby orders that it is not appropriate or necessary to implement the proposed federal standards of PURPA Sections 111(d)(18)-(19).

2. The Secretary to the Commission is hereby instructed to serve a copy of this Order on the Secretary of the Department of Energy of the United States of America.

3. This Order shall be effective on and after the date of its approval.

HARDY, ATTERHOLT, GOLC, LANDIS AND ZIEGNER CONCUR:

APPROVED: DEC 1 6 2009

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe,
Secretary to the Commission