STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGUALTORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	)	**CAUSE NO. 44688**

<u>SUBMISSION OF CAC & ELPC TESTIMONY</u>

Citizens Action Coalition of Indiana, Inc. (“CAC”), and the Environmental Law & Policy Center (“ELPC”) (collectively, “Joint Intervenors”), by counsel, respectfully submit the Direct Testimony and Exhibits of Mr. Karl R. Rábago (JI Exhibit 1) and Mr. John Howat (JI Exhibit 2).

Respectfully submitted,

Jennifer A. Washburn

Jennifer A. Washburn, Atty. No. 30462-49
Citizens Action Coalition of Indiana, Inc.
603 East Washington Street, Suite 502
Indianapolis, Indiana 46204
Phone: (317) 735-7764
Fax: (317) 290-3700
jwashburn@citact.org

CERTIFICATE OF SERVICE

The undersigned herby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 22nd day of January, 2016, to the following:

INDUSTRIAL GROUP
Bette J. Dodd
Todd A. Richardson
Jennifer W. Terry
Tabitha L. Balzer
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
BDodd@Lewis-Kappes.com
TRichardson@Lewis-Kappes.com
JTerry@Lewis-Kappes.com
TBalzer@Lewis-Kappes.com

LAPORTE COUNTY
Shaw R. Friedman
Friedman & Associates, P.C.
705 Lincolnway
LaPorte, IN 46350
sfriedman.associates@frontier.com

Reginald T. Badeaux IV
Deanna A Dean-Webster
Badeaux Dean-Webster LLP
310 North Alabama St., Ste. 305
Indianapolis, IN 46204
badeaux@bdwledgal.com
dean@bdwlegal.com

Keith Beall
Beall & Beall
13238 Snow Owl Dr., Ste. A
Carmel, IN 46033
kbeall@indy.rr.com

MUNICIPAL GROUP
Robert M. Glennon
Robert Glennon & Assoc., P.C.
3697 N. Co. Rd. 500 E.
Danville, IN 46122
glennon@iquest.net

OUCC
David Stippler
Scott Franson
Office of Utility Consumer Counselor
115 W. Washington St., Ste. 1500 South
Indianapolis, IN 46204
Dstippler@oucc.in.gov
sfranson@oucc.in.gov
infomgt@oucc.in.gov

UNITED STEELWORKERS
Antonia Domingo
United Steelworkers
60 Boulevard of the Allies, 8th Floor
Pittsburgh, PA 15208
adomingo@usw.org

U. S. STEEL
Nikki G. Shoultz
L. Parvin Price
BOSE MCKINNEY & EVANS LLP
111 Monument Circle, Suite 2700
Indianapolis, IN 46204
nshoultz@boselaw.com
pprice@boselaw.com

WAL-MART
Eric E. Kinder
Indiana Bar No.: 22646-02
Spilman Thomas & Battle, PLLC
300 Kanawha Boulevard, East
P. O. Box 273
Charleston, WV 25321
ekinder@spilmanlaw.com

NIPSCO
Claudia Earls
Erin Casper Borissov
NiSource Corporate Services - Legal
150 West Market Street, Suite 600
Indianapolis, Indiana 46204
cjearls@nisource.com
eborissov@nisource.com

Frank A. Shambo
Timothy R. Caister
Northern Indiana Public Service CO.
150 W. Market Street, Suite 600
Indianapolis, Indiana 46204
fshamb@nisource.com
tcaister@nisource.com

Kay E. Pashos
Michael B. Cracraft
Philip B. McKiernan
Ice Miller, LLP
One American Square, Suite 2900
Indianapolis, Indiana 46282-0200
kay.pashos@icemiller.com
michael.cracraft@icemiller.com
philip.mckiernan@icemiller.com

Carrie M. Harris
Spilman Thomas & Battle, PLLC
310 First Street, Suite 1100
P.O. Box 90
Roanoke, VA 24002-0090
charris@spilmanlaw.com

Barry A. Naum
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, PA 17050
bnaum@spilmanlaw.com

James W. Brew
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St., N.W.
8th Floor, West Tower
Washington, D.C. 20007
Phone: (202) 342-0800
Fax: (202) 342-0807
E-mail: jbrew@smxblaw.com

Anne E. Becker
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282-0003
Phone: (317) 639-1210
Fax: (317) 639-4882
Email: ABecker@lewis-kappes.com

Jennifer A. Washburn

JI Exhibit 1

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEUDLE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	**)**	**CAUSE NO. 44688**

DIRECT TESTIMONY OF KARL R. RÁBAGO
ON BEHALF OF CITIZENS ACTION COALITION AND
THE ENVIRONMENTAL LAW & POLICY CENTER

January 22, 2016

I. INTRODUCTION AND OVERVIEW

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

A. My name is Karl R. Rábago. I am the principal and sole member of Rábago Energy Limited Liability Company, a New York limited liability company with an office at 62 Prospect Street, White Plains, New York.

Q. On whose behalf are you appearing in this case?

A. I am appearing on behalf of the Citizens Action Coalition and the Environmental Law & Policy Center (collectively, Joint Intervenors).

Q. What is your relevant background and experience in the field of electric utility regulation?

A. I have more than 25 years' experience in the electric utility industry, including as a Public Utility Commissioner for the State of Texas, as a Deputy Assistant Secretary with the U.S. Department of Energy, as a utility executive and director of regulatory affairs, as an academic, and as an advocate. Through my position as Executive Director of the Pace Energy and Climate Center, I am active in all aspects of the groundbreaking New York Reforming the Energy Vision process, which seeks to develop and implement a blueprint for electric utility transformation. I am an attorney with degrees from Texas A&M University and the University of Texas School of Law, and post-doctorate degrees in military and environmental law from the U.S. Army Judge Advocate General's School and

Pace School of Law, respectively. A detailed resume is attached as Exhibit KRR-1.

Q. Have you previously testified before this or any other Commission?

A. I have not previously testified before the Indiana Utility Regulatory Commission (the Commission). In the past three years, I have submitted testimony, comments, or presentations in Commission proceedings in Ohio, New York, Rhode Island, Virginia, Georgia, Minnesota, Michigan, Missouri, Louisiana, North Carolina, Kentucky, Arizona, Florida, Wisconsin, and the District of Columbia. A listing of my recent testimony is attached as Exhibit KRR-2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the proposals by the Northern Indiana Public Service Commission (NIPSCO, or the Company) to increase fixed customer charges for residential and small business customers in this case.

Q. What information did you review in preparing this testimony?

A. I reviewed relevant materials in this case, including pre-filed testimony of the Company's witnesses, responses to information requests, statutes and regulations, and documents relating to other, relevant Commission proceedings.

Q. Do you have any financial relationship with the Company?

A. No. I do sit as the chair of the board of directors for the Center for Resource Solutions, a California not-for-profit organization that provides certifications for green power products under the Green-e® program. The Company offers such a product through its Green Power Rider. I do not participate in product-specific certification decisions at the Center for Resource Solutions, and would not participate in any matter relating to the Company's product certification where there existed a real or perceived conflict of interest.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. What legal and regulatory principles guide your review and testimony in this Cause?

A. I am guided by two important elements of law and regulation in this testimony. First, Indiana Code § 8-1-2-4 provides that "The charge made by any public utility for any service rendered or to be rendered either directly or in connection therewith shall be reasonable and just, and every unjust or unreasonable charge for such service is prohibited and declared unlawful." Second, pursuant to General Administrative Order (GAO) of the Indiana Utility Regulatory Commission 2013-5, "a utility petitioning for a change in its rates and charges bears the burden of proof and must submit sufficient evidence as part of its case in chief to satisfy its burden of proof."

Q. Do the Company's fixed customer charge proposals square with this guidance?

A. No. First, the Company has a burden to produce evidence and prove that its proposals are just and reasonable. In this regard, the foundation for the

Company's proposals lies in its Allocated Cost of Service Study (ACOSS). As Company Witness Gaske explains, development of the ACOSS involves three important and somewhat subjective steps—cost functionalization, cost classification, and cost allocation. While I did not review every unique decision involved in the functionalization, classification, and allocation of the Company's costs, it is important to note that reasonable people could differ on many of the imbedded decisions that purport to show the high levels of customer and fixed costs that the Company purports to assign to small customers. I address some of those decisions later in my testimony.

Second, the Company uses its ACOSS results to then make the unsupported argument that the broader interests of "fixed-variable alignment" require that the Commission support the proposals to increase fixed customer charges based solely on the Company's conclusion that a high percentage of the Company's costs are fixed. At their core, the Company proposals regarding "fixed-variable alignment" are based upon nothing more than the argument that there is greater certainty of revenue recovery for fixed costs that are collected through fixed charges than for fixed costs collected through volumetric or variable rates. It is impossible to agree with the Company unless one also believes several other impossible things first, including that the Company: (1) cannot set a volumetric rate adequate to ensure full recovery of justifiable fixed costs, (2) cannot improve its forecasting to better take account of variations in consumption levels against forecasts, (3) has no access to lost revenue adjustments associated with reductions in sales due to energy efficiency measures and programs, (4) has no right to request a rate case adjustment, (5) has no right to use a future test year forecast to address future sales volatility, (6) cannot petition the Commission for relief any time that it faces a real and measurable threat to its financial integrity due to revenue recovery shortfalls, and (7) will not, in fact, be motivated by guaranteed revenue recovery through fixed charges to overbuild its system, creating additional costs and problems. Guaranteed revenue recovery is not and never has been a goal of ratemaking. The Company has failed to demonstrate that it faces any financial harm due to current fixed cost recovery mechanisms that would justify its earnings guarantee proposals.

Finally, the Company's proposed fixed customer charges would create significant barriers and impediments to energy efficiency, conservation, and renewables that would result in improper discrimination against customers investing in these options. Again, the Company offers no evidence that customers who have or who are likely to invest in these options have created any harm that can best be remedied through the Company's fixed charge proposals.

Q. What are your findings based on your review of this case?

A. Based on my review of the Company's filings, I find that the Company proposals to increase the fixed customer charge for residential customers from $11/month to $20/month in proposed Rate 711, and to increase the fixed customer charge for small non-demand commercial customers from $20/month to $30/month in proposed Rate 721, are premised on flawed ratemaking and economic theory, will create serious adverse consequences for ratepayers, and will create improper incentives for the Company to manage costs and improve service.

Q. What conclusion do you reach in your testimony?

A. I conclude that the proposals to increase fixed customer charges in proposed Rates 711 and 721 are unjustified and would be unjust and unreasonable.

Q. What are your recommendations to the Commission?

A. I recommend that the Commission deny the increases reflected in the fixed customer charges in Rates 711 and 721. Any additional revenue requirement that is ultimately approved for these rates should be collected through the variable energy charges in those rates.

III. CUSTOMER CHARGES

Q. What does the Company propose regarding fixed customer charges for residential customers taking service from the Company?

A. NIPSCO proposes an increase of approximately 82% in non-bypassable customer charges for its residential customers.

Q. Does the Company also propose a customer charge increase for small business customers?

A. Yes. The Company proposes a 50% increase in the customer charge for small business customers. My testimony focuses on the impacts of the Company's proposal for residential customers, under proposed Rate 711. Though I do not further address the proposed small business customer charge rate increase in proposed Rate 721 in this testimony, I would note that:

- Increased customer charges have the same disincentive effect on commercial customers considering energy efficiency and distributed energy resource (DER) investments as they do on residential customers.
- Increased customer charges have the same devaluation impact on prior energy efficiency and DER investments for commercial customers as for residential customers.
- Increased customer charges have a similarly regressive economic impact on small businesses that are low users of energy as they do on low use residential customers.
- The Company's efforts to guarantee revenue collections through increased customer charges are antithetical to the goals and policy objectives of Senate Enrolled Act 412[1] to advance cost-effective energy efficiency programs and measures. Revenue collection intentionally tilted toward non-bypassable charges is economically what it appears to be—an effort to use rate design to extract monopoly rents and immunize the Company from the impacts of

[1] Ind. Code § 8-1-8.5-10 (2015).

efficient use of energy and the exercise of customer choice in meeting the need for electric service.

As with the residential customer charge proposals, I recommend that the Commission disapprove the fixed small business customer charge proposal in Rate 721 in favor of volumetric recovery of any underlying and prudent revenue requirement.

Q. Does the Company provide any distinguishing analysis or policy justification for the imposition of increased fixed customer charges for small business commercial customers, as opposed to residential customers?

A. No. The Company does not distinguish between customer classes in its attempt to justify its fixed charge proposals. I find that justification deficient as to both residential and small business customers.

Q. How does the Company justify its residential customer charge proposals?

A. The Company points to its cost of service analysis, which allocates fixed costs to residential customers. The cost of service classification and allocation methodologies chosen have the effect of assigning $22.51 per customer per month to the customer charge classification, and $83.95 per customer per month as fixed costs for residential customers. (Shambo, p. 36, lines 5-7.) Company Witness Shambo states that increasing fixed charges for customers "simply improves recovery of the fixed costs." (Shambo, p. 36, lines 2-3.) The Company cites a self-imposed limit of an aggregate increase resulting from all the proposals in this proceeding of not greater than 25.72% for residential customers, citing "the spirit of gradualism." (Shambo, p. 36, lines 9-10.)

Q. Does the Company cite any economic, ratemaking, or other justifications for its efforts to collect fixed costs through fixed charges?

A. Witness Shambo offers the Company's only arguments for increasing fixed charges. He states that the Company's policy objectives in this case are to achieve rates that "will better align the recovery of costs from the customers that drive those costs." (Shambo, p. 18, lines 15-16.) He further states that the Company seeks to "improve alignment of cost recovery with cost causation." Witness Shambo states that in addition to recovering costs from customers that cause the costs and properly aligning pricing signals and incentives, the goal of improving alignment of cost recovery to cost causation implies "fixed cost recovery through fixed charges." (Shambo, p. 20, lines 4-7.)

Q. What does the Company offer as evidence to support the idea that fixed cost recovery through fixed charges will improve alignment of cost recovery to cost causation?

A. The Company offers no evidence to support the concept that the nature of a cost, as either fixed or variable, should dictate the form of the charge used to recover such a cost. Citizens Action Coalition submitted Data Request 4-10, asking the Company to "provide all studies, reports, orders, or decisions relied upon by the

Company in pursuing “fixed-variable alignment” as cited by Witness Shambo at page 35 of Petitioner's Exhibit 2.” The Company responded that:

> NIPSCO’s proposal to take a relatively small step towards further fixed-variable alignment for residential rate design, as discussed by Frank A. Shambo at page 35, is based upon, in part, economic principles, experience, education, and various treatises, reports, studies, orders or decisions that are publicly available. NIPSCO would suggest that CAC review the Commission’s Orders in Cause Nos. 42943, 42767, 43046, 44062, 44063, and 43180. While these cases all involve gas utilities, it is worth noting that the gas business is a fixed cost business and that volumetric pricing makes it difficult for a utility to recover its approved revenue requirements in the face of declining usage, and also promotes a utility’s willingness to promote energy efficiency measures. See Cause No. 44124. In addition to Commission Orders, over the years, Mr. Shambo has reviewed materials from the National Association of Regulatory Utility Commissioners, National Resources Defense Council, other state public utility commission orders, previous orders of the Federal Energy Regulatory Commission, and reference material available from industry-based authors.

NIPSCO’s Response to CAC Data Request 4-10 is attached as Exhibit KRR-3.

Q. Did you review the Commission orders in the Causes cited by Mr. Shambo?

A. Yes. Those Causes primarily addressed: (1) gas utilities, identified by the Commission to be pure fixed cost businesses, (2) the impact of reduced sales volumes resulting from efficiency programs and measures, and (3) the setting of the Sales Reconciliation Component as a mechanism for decoupling revenues from sales volume.

Q. Does the Company offer any explanation about how or why the cited gas utility cases inform the setting of rates for an electric utility on the issue of fixed customer charges?

A. No. Given the adverse policy and fairness consequences of increased fixed customer charges, the gas utility cases cited by Witness Shambo should be afforded no weight in this proceeding. It is important to note that the Company proposal suffers from the fact that NIPSCO is a late arrival to the fixed charge proposal campaign—so late in fact, that the trend has already reversed in many places.[2]

Q. Does the Company offer any specific citations to the publicly available materials that Mr. Shambo has reviewed "over the years?"

A. No.

Q. What impact would the proposed increases in fixed customer charges have on the Company's residential customers?

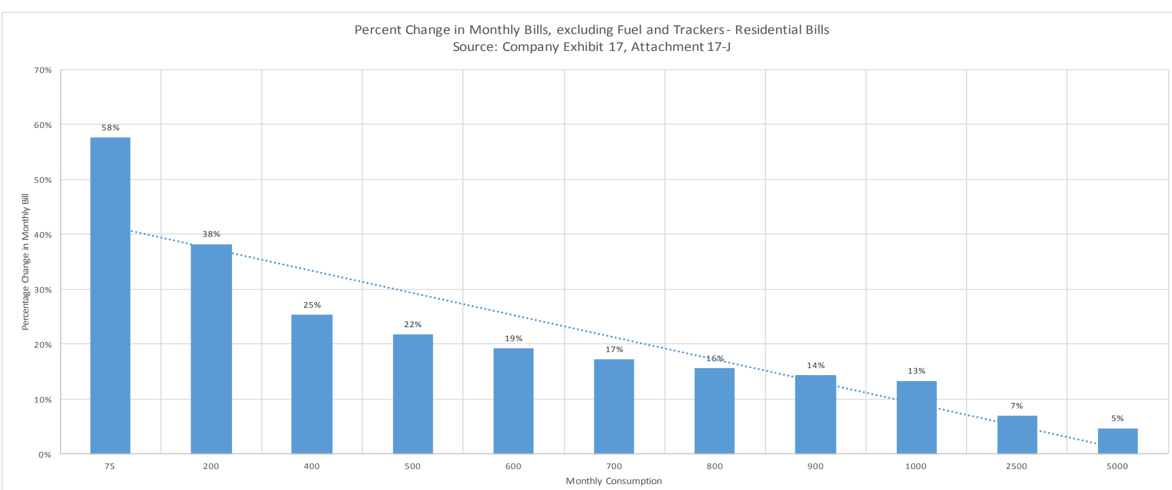
A. The proposed change would increase the fixed customer charge by 82% for residential customers. As demonstrated in the Company's Exhibit 17, Attachment 17-J, the impacts of these proposed changes are heavily allocated to low energy users. The Company estimates monthly bill increases of greater than 10% for any customer using fewer than 900 kWh per month, and less than 5% monthly bill increases for customers using 2,500 kWh or more per month. These impacts factor in fuel and tracker charges.

---

[2] *See* Kind, P., "Pathway to a 21st Century Electric Utility," CERES (Nov. 2015); available at: https://www.ceres.org/resources/reports/pathway-to-a-21st-century-electric-utility/view (attached as Exhibit KRR-4). See also Bade, G., "The future of rate design: Why the utility industry may shift away from fixed charges," UtilityDive.com (Nov. 19, 2015); available at: http://www.utilitydive.com/news/the-future-of-rate-design-why-the-utility-industry-may-shift-away-from-fix/409504/ (attached as Exhibit KRR-5).

Q. Does the fixed customer charge proposal impact some customers more than others?

A. Yes. Like the declining block rates of old, the fixed customer charge increases proposed by the Company impose their greatest burden on low use customers without regard for why they are low users, and minimize impacts on high use customers. While the residential class-wide increase proposed by the Company is a 12.47% increase in average monthly bills, the average monthly residential bill, not including trackers or fuel, increases by 17.24% under the Company proposal. This bill impact of these proposed changes differ dramatically with the level of residential consumption. The following NIPSCO chart depicts the impacts at various consumption levels selected by the Company, and demonstrates how heavily the impacts of the proposed fixed customer charge increase are skewed to low users:



Q. Does the Company propose future fixed customer charge increases in subsequent rate cases?

A. The Company implies that this case is only a first step, and that it will seek further and dramatic fixed charge increases in the future. Company Witness Gaske asserts that because of the way the Company performed its Allocated Cost of Service Study (ACOSS), it finds that customer and fixed costs for the residential and small business classes would be $83/month and $218/month, respectively. (Gaske, p. 48, lines 9-11.) Company Witness Shambo explains that as a "gradual approach" it is proposing to "mitigate" the impacts of its proposal in this case by limiting class rate changes at this time. (Shambo, p. 31, lines 3-5.) Nothing in the Company's case indicates that it will not seek further increases in the future.

Q. Are you familiar with what the Company calls "fixed-variable alignment"?

A. Company Witness Shambo identifies taking a step toward "fixed-variable alignment" as a Company objective in this case. (Shambo, p. 35, lines 17-18.) In my experience, I can find no authority in economic literature or regulatory practice, outside of utility proposals to increase fixed customer charges, for any principle that all fixed costs should always be recovered in fixed rates.

Q. Is Witness Shambo correct in stating that "aligning" fixed costs and fixed charges will help "align" cost recovery with cost causation?

A. No. This would create an appealing symmetry in nomenclature, but whether a cost is labeled as fixed or as variable tells us nothing about the most economic, just, and reasonable way to collect the cost from the customer class that caused it. Aligning cost recovery with cost causation is about trying to ensure that the quantity of the costs caused by the class is recovered from the class. Company Witness Gaske cites Bonbright's objectives for rate structures in his testimony. (Gaske, p. 40-41.) None of these principles bears any resemblance to the concept of "fixed-variable alignment."

Q. What would advancing the Company's "fixed-variable alignment" agenda accomplish then?

A. It would provide guaranteed revenues to the Company unrelated to usage and would impose the kind of non-bypassable charges that only a monopolist could get away with charging. It would encourage the Company to make wasteful and unnecessary investments in gold-plating their distribution system. It would encourage gaming in the ACOSS process in an effort to characterize more and more costs as "fixed." It would erect barriers to energy efficiency investments and impose increased burdens on low users of energy, who are often the poor, the elderly, students, and others on fixed incomes. It would create a barrier to growth in markets for energy efficiency and distributed generation. It would violate most of Bonbright's objectives for rate charges. This is hardly the path for a utility that seeks, in the words of Company Witness Sistovaris, "to be the premier utility in Indiana in every aspect of its performance, including interaction with its customers." (Sistovaris, p. 20, lines 12-13.)

Q. What do mean by "gold-plating," and why is it a concern?

A. I use the term "gold-plating" to describe behavior by the utility to spend more than is economically efficient—to make wasteful and unnecessary investments. Gold-plating means buying, upgrading, modifying, enhancing, or otherwise spending on things that are not necessary to efficiently and cost-effectively provide electric service. In the vertically-integrated electric utility system, this issue appeared as building too many and too expensive generation plants, and has been described as the Averch-Johnson effect.[3] Gold-plating can also be implemented through manipulation of cost of service studies to drive more costs into fixed cost categories to increase guaranteed recovery of those costs. In this case, I am making the point that the price signals in rate design go both ways. High fixed charges send a price signal to customers that it matters less how they change their level of consumption, because they can never avoid or reduce fixed charges. These charges also send a signal to utilities. The signal sent by high fixed charge rates is that wherever they can get away with it, utilities should try: (1) to functionalize everything possible as fixed costs, and (2) to over-build, or gold-plate, their distribution systems with wasteful and unnecessary fixed cost spending—because these costs will flow directly to fixed charges. A competitive market would not tolerate such behavior, and so it is a priority issue for regulators

[3] Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review* **52** (5): 1052–1069. JSTOR 1812181.

to not allow this rent seeking behavior, because regulators must act as a substitute for the forces of competition.

Q. Cannot the gold-plating problem be avoided through careful and detailed oversight of utility growth in fixed cost spending?

A. In theory, yes, but given the much greater administrative and regulatory burdens associated with detailed oversight of all the ways fixed costs are incurred in the distribution system, there are better approaches. In particular, regulators should look for rate structures that send powerful rate signals to utilities to ensure that investments are economically efficient, and not just a pathway to greater profits. Volumetric rate recovery of fixed costs for residential and small business customers accomplishes this result and properly aligns rate design with sound policy objectives.

Q. Would increasing fixed charges decrease revenue risk for the utility?

A. Yes. As such, any proposal to increase fixed charges should be offset by an equal proposal to reduce rate of return.

Q. Does not increased energy efficiency and reduced usage of energy create revenue problems for the utility?

A. Yes. Declining revenues are a problem for a utility that does not properly forecast its sales or properly account for trends in electricity consumption. Revenue shortfalls caused by declining sales can be remedied by non-bypassable fixed charges, but an increasing number of utilities and experts recognize that increasing fixed charges is a blunt and counterproductive tool for addressing the revenue issue. The Company could instead improve its forecasting skills, file more frequent rate cases, or use a future test year in rate cases, for example. Rather than focus on the embedded or sunk fixed costs only, the Company could improve its understanding of how reduced sales can help defer or avoid future fixed costs, and adjust its construction and equipment replacement budgets accordingly. Among all its choices, increasing fixed customer charges to stabilize revenues is the most regressive, most punitive, and most uneconomic option available.

Q. Is there any merit in increasing fixed customer charges "just a little"?

A. No. Proper cost allocation ensures that customers who cause the costs bear those costs. Increasing fixed customer charges does not improve cost allocation, only the collection of monopoly rents. Even small customer charge increases can have profound impacts on the household budgets of the poor, and actually subsidize customers who are high users and high cost causers.

Q. Are there any costs that should be collected through fixed charges?

A. Yes. Only those costs that strictly vary only according to the number of customers should be recovered through fixed charges. In this case, the Company has allocated a wide range of costs to customer charges—including a general category of customer services, transformers, AMR meter reading, and customer information and advertising—that do not strictly vary only with the number of customers. (Company Exhibit 17, Attachment 17-E, p. 4 of 9.) As a result, the Company has allocated $22.51 to customer charges. The fixed customer charge should be limited to the costs of the service drop, the cost of the meter attributable to billing, billing and collection costs, and other costs that vary exclusively with customer count. For most utilities in the United States, these customer costs do not exceed $10 per month.[4]

Q. Are there benefits to using volumetric charges, instead of fixed charges, to recover fixed costs?

A. Volumetric charges can be used to recover fixed costs associated with distribution infrastructure while also sending a price signal to customers to decrease usage and lower their bills. The use of volumetric charges instead of increasing fixed charges also lessens the disproportionate impact on low use and low-income consumers.

Furthermore, to advance the adoption of cost-effective energy efficiency and to reduce the cost of energy efficiency programs provided by utilities, it is important to provide incentives to reduce usage – such as shifting costs *away* from fixed customer charges to volumetric delivery charges instead. As a result, the Commission should take a hard look at any request to increase fixed customer charges, and to the costs that are actually allocated to customer charges.

[4] *See* Lazar, J. & Gonzalez, W., "Smart Rate Design for a Smart Future," Regulatory Assistance Project (Jul. 2015), at 36; available at: http://www.raponline.org/document/download/id/7680.

A. IMPACTS ON LOW USE AND LOW INCOME CUSTOMERS OF INCREASING CUSTOMER CHARGES

Q. Do increases in fixed charges pose potential problems for low-income and low usage customers?

A. Yes. Increasing fixed charges can have disproportionate impacts on low usage customers (who are often low-income customers), customers on fixed incomes (frequently seniors), students, and customers who have aggressively pursued green building and energy efficiency. This is an area where the Company needs to demonstrate definitively that low-income customers will not be unfairly affected, but the Company fails to address the issue adequately in testimony.

Q. How does a change to higher fixed charges impact low- and moderate-income customers and other low use customers?

A. Allocation of costs to fixed, non-bypassable charges imposes a significant burden on low energy users who are low- and moderate-income customers, or customers on fixed incomes, many of whom are the elderly. The higher fixed charge is economically regressive. This "reverse Robin Hood" proposal likely subsidizes the well-to-do at the expense of the low use, often low-income, users.

Q. What is the Company's position on the impact of increased fixed customer charges on low-income customers?

A. The Company's testimony demonstrates that increases in customer charges will disproportionately affect low *use* customers, which could indicate that there will likely be a disproportionate effect on low-income customers. (Company Exhibit 17, Attachment 17-J.) Company Witness Shambo asserts that they reviewed the usage levels for low-income customers and found them higher than those for the "normal" population. (Shambo, p. 36, lines 14-16.)

Q. Does this information address your concern about low-income, low use customers?

A. No. The chart provided by Witness Shambo in Attachment 2-C does not prove the argument asserted. The Company does not indicate that the sample selected for review is representative of low-income customers in general. The Company does not indicate whether the relatively large number of "normal" residential customers in the 25 kwh/month, 100 kWh/month, and 200 kWh/month bins includes vacation or second home bills. (NIPSCO Response to CAC Request 4-005, attached as Exhibit KRR-6.) The chart appears to include only customers with 12 monthly bills, which may not be inclusive of all low-income customers. There is no way to tell whether the data selected for the chart fairly addresses the issue of whether low-income customers tend to be lower or higher user than other residential customers. It is important to note that the National Association of State Utility Consumer Advocates ("NASUCA") has looked at the fixed customer charge issues and recently adopted a resolution opposing and urging utility commissions to reject increased delivery service customer charges because of their tendency to adversely impact the poor, the elderly, racial minorities, and customers on fixed incomes.[5]

Q. Do you have other concerns about the impacts of customer charge increases on low-income customers?

A. Yes. The Company fails to address the important issue of household energy burden. The Company admits that it has no data on low-income household income or energy burdens. (NIPSCO Responses to CAC Requests 4-006, 4-007, attached as Exhibit KRR-8.)

Q. What do you mean by household energy burden?

A. Household energy burden refers to the share of household expenses reflected by energy costs. A more comprehensive analysis of the impacts of the fixed customer charge proposals would account for household income levels in low-income and low use households.

Q. Does the Company propose any measures to mitigate the impact or potential impact of the increased fixed customer charges on low-income or low use customers?

A. Yes. The Company proposes a single bill credit of $50 to be applied to the June bills of customers who receive LIHEAP funding. (Shambo, p. 38, lines 3-10.)

---

[5] National Association of State Utility Consumer Advocates, "Resolution 2015-1: Opposing Gas and Electric Utility Efforts to Increase Delivery Service Customer Charges," (Jun. 9. 2015); available at: http://nasuca.org/customer-charge-resolution-2015-1/ (attached as Exhibit KRR-7).

Q. Do you find this to be a meaningful measure to address the needs of low-income customers or the problems created by the proposal to increase fixed customer charges?

A. No. The annual impact of the proposed fixed customer charge occurs in all twelve months, and totals $108 for the year. A one-time $50 credit offsets less than one-half of the proposed fixed customer charge increase. Moreover, the credit will not encourage energy efficiency, and will not address high bills in other months. Finally, the Company submits no evidence that receipt of LIHEAP funding is the best or even a good basis for characterizing the universe of customers who would be adversely impacted by the Company's fixed charge proposal.

B. IMPACTS ON ENERGY EFFICIENCY AND OTHER DISTRIBUTED ENERGY RESOURCES OF INCREASING CUSTOMER CHARGES

Q. How does increasing fixed customer charges specifically impact customer investment in energy efficiency, conservation, and other distributed energy resources (DER)?

A. Increases in non-bypassable fixed customer charges create powerful price signals ***against*** investment in energy efficiency, distributed generation, and other DER products and services, which would frustrate attainment of energy efficiency goals established pursuant to Senate Enrolled Act 412.

Q. Did the Company consider the impact of their proposed increase in the fixed customer charge on energy efficiency, conservation, and DER?

A. I found no information in the record that the Company considered or analyzed the impacts of their proposals on demand for DER. I find this omission striking. The Company confirmed in response to CAC Request 6-007 that it has done no analysis of the potential impact of its fixed customer charge proposal on energy efficiency uptake and adoption by its customers (attached as Exhibit KRR-9).

Q. Why should the Commission be concerned about approving a rate design that is detrimental to DER?

A. Advancing the increased reliance on DER supports achieving goals of energy service affordability, environmental improvement, and market development. The benefits of increased DER markets include resource diversification, future cost reductions associated with increased volume of deployment (economies of scale), job creation, system-wide cost reductions, and leveraging of non-utility investment dollars, among others.

Q. How do energy efficiency and conservation in particular produce these benefits?

A. Energy efficiency and conservation generate benefits to the utility, ratepayers, and society in many ways, including lower cost than traditional generation and infrastructure investments, downward pressure on rates over the mid- and long-term, persistent and consistent savings, nearly endless resource potential due to economies of manufacturing scale and technological innovation, broad availability to all classes of customers, and significant externalized benefits often not accounted for in ratemaking.

Q. Can affected customers avoid customer charges with more efficient energy use or deployment of other DER?

A. No. The higher customer charge cannot be avoided by customer reductions in energy use through efficiency, conservation, or other DER measures. The proposed monthly customer charge increase for NIPSCO is the equivalent of about 82 kWh of volumetric delivery charges each month.

Q. What do these changes mean to the energy savings opportunity for residential customers?

A. The Company's proposal means that low use customers (using 500 kWh or fewer per month) will have to first reduce or offset consumption by at least 15% (based on the Company's bill impact assessments) to offset the bill impact of the proposed customer charge increase before they can even start thinking about reducing their overall bill through energy efficiency or other DER investments. Fixed customer charges are "unavoidable" and reduce the marginal value and the ultimate bill value to those customers who have taken action to reduce their energy consumption. These proposed changes will also have a chilling impact on customers who are contemplating such energy efficiency investments, especially in light of the Company's implied intentions to further increase customer charges to further its pursuit of guaranteed revenues through what it calls "fixed-variable alignment." The higher customer charge is a non-bypassable connection tax that makes serious investment in energy efficiency less cost-effective and potentially futile.

Q. How does a change to higher customer charges impact prior customer investments in energy efficiency?

A. Allocation of costs to fixed, non-bypassable charges adversely affects customers who have already invested in energy efficiency and other DER options, and also has a chilling impact on customers who are contemplating such energy efficiency and DER investments, especially in light of the Company's apparent intentions to further increase fixed customer charges up to implied by their cost allocation and assignment methodologies. Increased fixed customer charges also impose an extraordinary burden and destroy investment-backed savings expectations on low energy users who have made significant prior investments in order to lower their bills. Customers—including residential, small commercial, and other customer classes—and communities that invest in weatherization, equipment improvements, distributed generation, and building remodeling do so with payback expectations in mind. An increased fixed charge is like a regulatory taking from customers who have made good faith investments in greater efficiency and self-reliance. As explained above, the Company proposal is like taking almost 1,000 kWh per year out of the planned savings stream for those customers, extending the payback period they had planned upon, and frustrating their investment economics. This is irreversible damage to the customers that could be avoided without harm to the Company by simply allocating the revenues associated with the fixed charge increase proposal to volumetric rates instead.

Q. What is the likely long-term impact of reduced energy efficiency, conservation, and development of renewable energy?

A. Inefficient use means uneconomically high levels of energy consumption. This excess use, in turn, leads to demand for more expensive power plants and infrastructure. The costs of those investments are levied on consumers and raise their rates. Following the Company's logic in this rate application means that in the long term, more costs would be allocated to demand and fixed charges, creating higher non-bypassable charges irrespective of electrical usage. And so on. The Company's proposal seems likely to start a death spiral of electric service unaffordability.

Q. Does the Company address the issue of increasing customer interest in distributed generation and energy efficiency and the potential impacts of increased fixed charges on those customers?

A. Company Witness Shambo testifies that customers who invest in distributed generation and energy efficiency could impact the Company's ability to recover its expenses and its cost of capital by causing it to under-recover its fixed costs and eventually shift those costs to other customers. (Shambo, p. 22, lines 11-17.)

This argument lacks merit. First, as previously explained, under-recovery due to reductions in sales is primarily a problem of poor forecasting, and is limited to the period between rate cases. The Company offers no evidence that such under-recovery exists or has significant financial impact on the Company's earnings. This is not surprising given the tiny number of NIPSCO customers who are customer generators.

Q. How many residential customers are customer generators in the Company's service territory?

A. According to the Company response to CAC Request 6-001, Attachment B (attached as Exhibit KRR-10), the numbers are very, very small. The Company has about 410,000 residential customers, and about 51,000 small commercial customers. The number of customer generators, according to the Company, is as follows:

CAC Request 6-001 b.							
Total Number of Customers[1] with Distributed Generation by Rate							
		Customer Class	2010	2011	2012	2013	2014
		611	34	46	46	53	67
		621	0	3	7	9	13

What this means is that customer generators represent about 0.016% of residential customers, and about 0.025% of small commercial customers.

Q. How do these customers impact their bills with self-generation, and how do customer-generators impact Company revenues, now and in the future?

A. We don't know. In response to CAC Request 6-001 (attached as Exhibit KRR-11), the Company does not know how distributed generation from residential and small business distributed generation impacts revenues. In response to CAC Request 6-002 (attached as Exhibit KRR-12), the Company reports that it has no idea how many distributed generation systems will be installed by residential and small business customers over the next five years. In response to CAC Request 6-003 (attached as Exhibit KRR-13), the Company reports that it has conducted no analysis to confirm the existence or magnitude of actual under-recovery due to customer generators. In response to CAC Request 6-004 (attached as Exhibit KRR-14), the Company reports that distributed generation reduces sales, but it cannot account for the specific impacts per customer.

Q. Does the Company address whether distributed generation customers impact distribution system costs due to changes in their energy use?

A. No. Customers who use less energy make less use of the system, reducing wear and tear and offsetting future fixed costs. The wholesale imposition of fixed customer charge increases to address speculative earnings issues associated with the tiny fraction of customers who invest in distributed generation or energy efficiency is a disproportionate and unfair imposition of burden on all residential and small business customers. In the interests of administrative efficiency and fairness, the Commission should not approve any action to address this tiny issue until the Company meets its burden of proof by demonstrating the nature of the problem and a reasonable response.

C. THE MERITS OF RECOVERING REVENUES THROUGH VOLUMETRIC RATES INSTEAD OF FIXED CUSTOMER CHARGES

Q. Does the Company have alternatives to allocating increased costs to fixed customer charges?

A. Yes. A fixed customer charge is not the only mechanism for recovering fixed costs. Precisely because of the concerns that I summarized above, utilities and regulators have often allocated a large proportion of fixed costs to volumetric rate elements for residential and small commercial customers. The Company uses a volumetric delivery charge that could help carry whatever revenue requirement is ultimately and properly allocated to residential customers. Volumetric charges can be used for the small commercial Rate 721 as well. Even assuming the full revenue requirement sought by the Company in this Cause, I estimate that collecting the proposed fixed customer charge increases through volumetric rates would increase the rate by $0.0129/kWh for Rate 711, and $.0040/kWh for Rate 721.

Q. Does the use of volumetric rates to carry fixed costs present a financial integrity risk to the utilities that could be remedied with higher customer charges?

A. No. First, the rate making principle is that rates should reflect costs, not that they be perfectly aligned with cost structure. As I previously stated, properly reflecting costs means that the costs caused by a class of customers are charged to those customers. It does not mean that economic efficiency or sound policy is advanced by seeking guaranteed recovery of fixed costs through fixed charges. Second, the Company could use a future test year and take more frequent opportunities to adjust rates in periodic rate cases. There is no statistical likelihood of any real risk to the Company's financial integrity due to some customers using less energy than if the utility had forecast in the interval between reasonably timed rate cases. The adverse impact on low use, low-income, and fixed income elderly customers, as well as the economics of efficient use of energy, outweighs any speculative short-term risk to the Company's earnings.

Q. Does the Company address any other opportunities to reduce the adverse impacts of its proposed customer charge proposals?

A. No. In particular, the Company does not assess the respective impact of allocating its proposed revenue requirements to volumetric distribution charges. Assigning the revenue requirement to the volumetric delivery charge would spread the increase across all energy use, and result in a more gradual increase.

Q. Company Witness Shambo asserts that "designing rates to favor low usage customers in an effort to help [low-income] customers" is not appropriate. (Shambo, p. 37, lines 7-8.) Is that what you are arguing for?

A. Not at all. Costs increase with use, so rates that encourage lower use help reduce costs for all customers. Assigning revenues to volumetric rates instead of fixed customer charges would have the additional beneficial policy outcome of being less burdensome to low-income customers.

Q. Why is it appropriate to consider recovering fixed costs through volumetric rates?

A. It is appropriate because of the price signal function of properly designed rates. Properly designed rates ***reflect*** properly allocated costs ***and*** send signals for efficient consumption in the future. Sunk fixed costs, the focus of the Company's concern in their customer charge proposals, can be reflected in ***either*** the fixed charge or a volumetric charge. A customer's demand, especially for low-income and low use customers, is largely a function of the energy performance of their home, which is often rented; their major appliances, which are often expensive to replace or upgrade; and the weather. Imposing high fixed costs on these customers is the economic regulation equivalent of suggesting that we "let them eat cake." An efficient price signal (that is, one that customers can respond to without disconnecting from all service) relating to future fixed costs can ***only*** be communicated with a volumetric charge. To meet sound public policy and ratemaking objectives, it is very important to send price signals that can motivate and reward economically efficient consumption decisions. That is why a volumetric charge is the optimal rate design in this case for any merited revenue requirement increases.

Q. Does volumetric charge recovery of fixed customer costs violate principles of ratemaking or sub-optimize the economic efficiency of rates?

A. No. Sound ratemaking is based on ensuring that costs are properly allocated to customer classes based on cost causation. I know of no ratemaking or economic principle that finds that cost *structure* must be exactly replicated in rate *design*, especially when significant negative policy impacts are attendant to that approach. As I previously testified, traditional ratemaking limits customer charges to certain basic customer connection costs—the meter, billing services, and other similar general and administrative costs. These are fixed costs that vary by customer count and typically form the basis and limit for fixed customer charges. Even so, when the policy impacts discussed above are considered, some of these costs are best collected through variable charges.

Q. When costs associated with distribution systems are classified as fixed, should they be collected through the non-bypassable customer charge?

A. Not necessarily, and not if the result is that low usage customers are disproportionately impacted or that adverse impacts on energy efficiency, conservation, and DER also result. Recently in other states, some utilities have argued that increased fixed customer charges secure revenue recovery in a world where customers have more options to reduce their level of usage. I am not aware of any evidence or analysis, and see none in this record, that increasing fixed customer charges improves system-wide economic efficiency, the efficiency of *customer* decisions, or the ability of the Company to meet its objectives as laid out by Company Witness Sistovaris to be a premier utility in its interactions with its customers. (Sistovaris, p. 20, lines 12-13.) Absent evidence of system-wide or customer efficiency benefits, and proof that this type of rate structure will advance policy and regulatory objectives, fixed customer charges should not be increased and costs should instead be allocated to variable charges. Again, the differences in costs that lead to labeling them as fixed or variable does not, standing alone, tell us anything about the rate design that should be used to recover them.

Q. How do customers exercise control over their variable and fixed costs?

A. The benefit of using volumetric rates to recover both fixed and variable costs is that class costs are still properly reflected in rates, and that customers have meaningful, practical, and realistic opportunities to exercise control over their energy bills and costs. Reductions in use—through efficiency, conservation, or self-generation—all contribute to reductions in variable energy costs. Moreover, these behaviors also reduce high peak demand, and by doing so, customers directly contribute to reduced fixed costs going forward. Efficiency, demand response, west-facing solar, and other options allow customers to contribute to fixed cost reduction, and all of these are frustrated by shifting cost recovery from volumetric to fixed charges, as proposed by the Company. There is no evidence in the record that the Company considered these or other benefits associated with distributed energy resources.

Q. Do increased fixed charges impact volumetric charges?

A. Yes. All other things being equal, increased fixed charges result in lower volumetric charges. Lower volumetric charges weaken the short- and mid-term price signal customers receive relating to their consumption. In this way, increased fixed charges are economically equivalent to and exacerbate the uneconomic behavior encouraged by declining block electric rates.

IV. FINDINGS, CONCLUSIONS, AND RECOMMENDATIONS

Q. What are your findings based on your review of this case?

A. Based on my review of the Company's filings, I find that the Company proposals to increase the fixed customer charge for residential customers from $11/month to $20/month in proposed Rate 711, and to increase the fixed customer charge for small non-demand commercial customers from $20/month to $30/month in proposed Rate 721, are premised on flawed ratemaking and economic theory, will create serious adverse consequences for ratepayers, and will create improper incentives for the Company to manage costs and improve service.

Q. What problems does the Company identify in its current rates to justify its efforts to increase "fixed-variable alignment?"

A. None. Other than to say that its Allocated Cost of Service Study ("ACOSS") shows that not all of what it classifies as fixed costs are recovered in its fixed charges, the Company witnesses produced no studies, surveys, analysis, or other data to demonstrate the actual existence of any actual problems manifest in faulty rate design. Company Witnesses Shambo and Gaske (1) fail to quantify with any numbers or analysis any economic inefficiency that attends to current rate structures, (2) fail to quantify the purported under-recovery of revenues associated with fixed customer charges or facilities charges that they argue are currently too low, (3) fail to provide evidence that customers are under-using electric energy because they improperly consider it too valuable, (4) fail to demonstrate that current energy efficiency programs and participation rates are excessive or not cost-effective as a result of incorrectly set customer fixed charges, (5) fail to demonstrate that the utility has suffered chronic under-recovery problems as a result of incorrectly set customer fixed charges, and (6) fail to demonstrate with evidence that the Company has suffered any adverse cost-of-financing or other threats to its financial integrity as a result of incorrectly set customer fixed charges.

Q. Why are these failures significant?

A. These failures are significant because under generally held principles of regulatory practice, the utility has both the burden of production and persuasion in seeking to establish and modify rates. And in failing to meet those burdens, the Company's proposed fixed customer charges cannot be found to be just and reasonable.

Q. What ultimate conclusion do you reach in your testimony?

A. I conclude that the proposals to increase fixed customer charges in proposed Rates 711 and 721 are unjustified and would be unjust and unreasonable.

Q. What are your recommendations to the Commission?

A. I recommend that the Commission deny the increases reflected in the fixed customer charges in Rates 711 and 721. Any additional revenue requirement that is ultimately approved for these rates should be collected through the variable energy charges in those rates.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Karl R. Rábago, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

________________________________ ___January 22, 2016____________________

Karl R. Rábago Date

EXHIBIT KRR-1

Karl R. Rábago

Rábago Energy Limited Liability Company
62 Prospect Street, White Plains, New York 10606

c: +1.512.968.7543 e: karl@rabagoenergy.com

Summary

Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a public utility regulatory commissioner, educator, research and development program manager, utility executive, business builder, federal executive, corporate sustainability leader, consultant, and advocate. Highly proficient in advising, managing, and interacting with government agencies and committees, the media, citizen groups, and business associations. Successful track record of working with US Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. National and international contacts through experience with Pace Energy and Climate Center, Austin Energy, AES Corporation, US Department of Energy, Texas Public Utility Commission, Jicarilla Apache Tribal Utility Authority, Cargill Dow LLC (now NatureWorks, LLC), Rocky Mountain Institute, CH2M HILL, Houston Advanced Research Center, Environmental Defense Fund, and others. Skilled attorney, negotiator, and advisor with more than twenty-five years of experience working with diverse stakeholder communities in electricity policy and regulation, emerging energy markets development, clean energy technology development, electric utility restructuring, smart grid development, and the implementation of sustainability principles. Extensive regulatory practice experience. Nationally recognized speaker on energy, environment and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at Pace University School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Post-doctorate degrees in environmental and military law. Military veteran.

Employment

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY SCHOOL OF LAW

Executive Director: May 2014—Present.

Leader of a team of professional and technical experts in energy and climate law, policy, and regulation. Secure funding for and manage execution of research, market development support, and advisory services for a wide range of funders, clients, and stakeholders with the overall goal of advancing clean energy deployment, climate responsibility, and market efficiency. Supervise a team of employees, consultants, and adjunct researchers. Provide learning and development opportunities for law students. Coordinate efforts of the Center with and support the environmental law faculty. Additional activities:

- Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-present). The NESEMC is a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC seeks to harmonize solar market policy and advance best policy and regulatory practices in the northeast United States.
- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board (formerly the Green Power Board).

- Director, Interstate Renewable Energy Council (IREC) (2012-present). IREC focuses on issues impacting expanded renewable energy use such as rules that support renewable energy and distributed resources in a restructured market, connecting small-scale renewables to the utility grid, developing quality credentials that indicate a level of knowledge and skills competency for renewable energy professionals.

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing expert witness and policy formulation advice and services to organizations in the clean and advanced energy sectors. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Government and regulatory affairs manager for AES Wind Generation, one of the largest wind companies in the country. Manage a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets. Active in national policy and the wind industry through work with the American Wind Energy Association as a participant on the organization's leadership council. Also served as Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Authored and implemented a standard of practice based on ISO 14064 and industry best practices. Commissioned the development of a suite of methodologies and tools for various greenhouse gas credit-producing technologies. Also served as Director, Global Regulatory Affairs, providing regulatory support and group management to AES's international electric utility operations on five continents. Additional activities:

- Director and past Chair, Jicarilla Apache Nation Utility Authority (1998 to 2008). Located in New Mexico, the JAUA is an independent utility developing profitable and autonomous utility services that provides natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan.

Houston Advanced Research Center

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications, an industry-driven testing and evaluation center for near-commercial fuel cell generators; the Gulf Coast Combined Heat and Power Application Center, a state and federally funded initiative; and the High Performance Green Buildings Practice, a consulting and outreach initiative. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector. Developed and launched new and integrated program activities relating to hydrogen energy technologies, combined heat and power, distributed energy resources, renewable energy, energy efficiency, green buildings, and regional clean energy development. Active participant in policy development and regulatory implementation in Texas, the Southwest, and national venues. Frequently engaged with policy, regulatory, and market leaders in the region and internationally. Additional activities:

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, leader and manager of successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative acts as an umbrella structure for a number of biofuels related projects, including emissions evaluation for a stationary biodiesel pilot project, feedstock development, and others.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

Cargill Dow LLC (now NatureWorks, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Founded in 1997, NatureWorks, LLC is based in Minnetonka, Minnesota. Integrated sustainability principles into all aspects of a ground-breaking biobased polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives. NatureWorks is the first company to offer its customers a family of polymers (polylactide – "PLA") derived entirely from annually renewable resources with the cost and performance necessary to compete with packaging materials and traditional fibers; now marketed under the brand name "Ingeo."

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

Rocky Mountain Institute

Managing Director/Principal: October 1999–April 2002. In two years, co-led the team and grew annual revenues from approximately $300,000 to more than $2 million in annual grant and consulting income. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Worked to increase market opportunities for clean and distributed energy resources through consulting, research, and publication activities. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles. Frequent appearance in media at international, national, regional and local levels.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs for a not-for-profit environmental group with a staff of 160 and over 300,000 members. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Initiated and managed nationwide collaborative activities aimed at increasing use of renewable energy and energy efficiency technologies in the electric utility industry, including the Green-e Certification Program, Power Scorecard, and others. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Developed, coordinated, and advised on legislation, policy, and renewable energy technology development within the Department, among other agencies, and with Congress. Managed, coordinated, and developed international agreements for cooperative activities in renewable energy and utility sector policy, regulation, and market development between the Department and counterpart foreign national entities. Established and enhanced partnerships with stakeholder groups, including technology firms, electric utility companies, state and local governments, and associations. Supervised development and deployment support activities at national laboratories. Developed, advocated and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Laid the groundwork for legislative and regulatory adoption of integrated resource planning, electric utility restructuring, and significantly increased use of renewable energy and energy efficiency resources. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT). Member, Southern States Energy Board Integrated Resource Planning Task Force. Member of the University of Houston Environmental Institute Board of Advisors.

LAW TEACHING

Professor for a Designated Service: Pace University Law School, 2014-present. Non-tenured member of faculty. Courses taught: Energy Law. Supervise a student clinical effort that engages in a wide range of advocacy, analysis, and research activities in support of the mission of the Pace Energy and Climate Center.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law. Provided *pro bono* legal services in administrative proceedings and filings at the Texas Public Utility Commission.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar. Greatly expanded the environmental law curriculum and laid foundation for the concentration program in law. While carrying a full time teaching load, earned a Master of Laws degree in Environmental Law. Established a program for subsequent environmental law professors to obtain an LL.M. prior to joining the faculty.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate. Prosecuted and defended more than 150 felony-level courts-martial. As prosecutor, served as legal officer for two brigade-sized units (approximately 5,000 soldiers), advising commanders on appropriate judicial, non-judicial, separation, and other actions. Pioneered use of some forms of psychiatric and scientific testimony in administrative and judicial proceedings.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Selected Publications

"The Clean Power Plan," Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

"The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age," co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

"Rethinking the Grid: Encouraging Distributed Generation," Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

"The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff," Solar Industry, Vol. 6, No. 1 (Feb. 2013)

"A Review of Barriers to Biofuels Market Development in the United States," 2 Environmental & Energy Law & Policy Journal 179 (2008)

"A Strategy for Developing Stationary Biodiesel Generation," Cumberland Law Review, Vol. 36, p.461 (2006)

"Evaluating Fuel Cell Performance through Industry Collaboration," co-author, Fuel Cell Magazine (2005)

"Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production," co-author, Polymer Degradation and Stability 80, 403-19 (2003)

"An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options," contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

"Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size," co-author, Rocky Mountain Institute (2002)

"Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado," with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

"Study of Electric Utility Restructuring in Alaska," with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

"New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers," EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

"Building a Better Future: Why Public Support for Renewable Energy Makes Sense," Spectrum: The Journal of State Government (Spring 1998)

"The Green-e Program: An Opportunity for Customers," with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

"Being Virtual: Beyond Restructuring and How We Get There," Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

"Information Technology," Public Utilities Fortnightly (March 15, 1996)

"Better Decisions with Better Information: The Promise of GIS," with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

"The Regulatory Environment for Utility Energy Efficiency Programs," Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

"An Alternative Framework for Low-Income Electric Ratepayer Services," with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

"What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act," Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

"Least Cost Electricity for Texas," State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

"Environmental Costs of Electricity," Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

EXHIBIT KRR-2

Table of Testimony Submitted by Karl R. Rábago, Rábago Energy LLC
(as of 20 January 2016)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia SCC Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia PSC Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 1203	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana PSC Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia PSC Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia PSC Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia SCC Case # PUE-2013-00088	Environmental Respondents
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jul. 10, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida PSC Docket # 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy
Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri PSC File No. ET-2014-0350, Tariff # YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia SCC Case # PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)

Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin PSC Docket # 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin PSC Docket # 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin PSC Docket # 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case # 14AC-CC00316	SOLAR, LLC
Ongoing	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California PUC Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York PSC Case # 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan PSC Case # U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i PUC Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisc. PSCo Rate Application	Wisconsin PSC Case # 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2015 IRP	VA SCC Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York PSC Cases 15-E-0283, -0285	Pace Energy and Climate Center
Oct. 14, 2015	Florida Power & Light Application for CCPN for Lake Okeechobee Plant	Florida PSC Case 150196-EI	Environmental Confederation of Southwest Florida
Oct. 27, 2015	Appalachian Power Company 2015 IRP	VA SCC Case # PUE-2015-00036	Environmental Respondents
Nov. 23, 2015	Narragansett Electric Power/National Grid Rate Design Application	Rhode Island PUC Docket No. 4568	Wind Energy Development, LLC
Dec. 8, 2015	State of West Virginia, et al., v. U.S. EPA, et al.	U.S. Court of Appeals for the District of Columbia Circuit Case No. 15-1363 and Consolidated Cases	Declaration in Support of Environmental and Public Health Intervenors in Support of Movant Respondent-Intervenors' Responses in Opposition to Motions for Stay

Dec. 28, 2015	Ohio Power/AEP Affiliate PPA Application	PUC of Ohio Case No. 14-1693-EL-RDR	Environmental Law and Policy Center
Jan. 19, 2016	Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company Application for Electric Security Plan (FirstEnergy Affiliate PPA)	PUC of Ohio Case No. 14-1297-EL-SSO	Environmental Law and Policy Center

EXHIBIT KRR-3

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 4

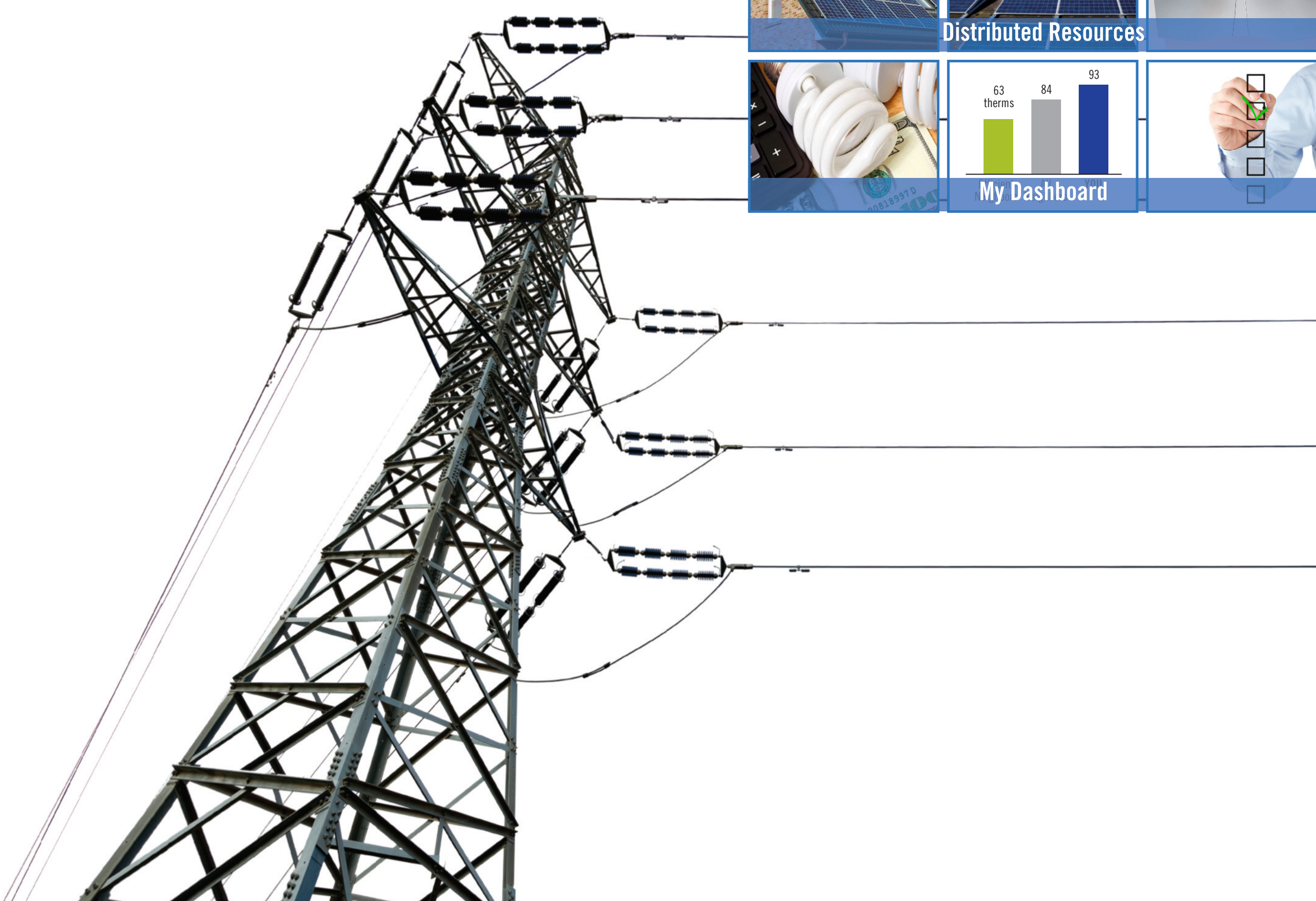
CAC Request 4-010:
Please provide all studies, reports, orders, or decisions relied upon by the Company in pursuing "fixed-variable alignment" as cited by witness Shambo at page 35 of Petitioner's Exhibit 2.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks publicly available information.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's proposal to take a relatively small step towards further fixed-variable alignment for residential rate design, as discussed by Frank A Shambo at page 35, is based upon, in part, economic principles, experience, education, and various treatises, reports, studies, orders or decisions that are publicly available. NIPSCO would suggest that CAC review the Commission's Orders in Cause Nos. 42943, 42767, 43046, 44062, 44063, and 43180. While these cases all involve gas utilities, it is worth noting that the gas business is a fixed cost business and that volumetric pricing makes it difficult for a utility to recover its approved revenue requirements in the face of declining usage, and also promotes a utility's willingness to promote energy efficiency measures. See Cause No. 44124. In addition to Commission Orders, over the years, Mr. Shambo has reviewed materials from the National Association of Regulatory Utility Commissioners, National Resources Defense Council, other state public utility commission orders, previous orders of the Federal Energy Regulatory Commission, and reference material available from industry-based authors.

EXHIBIT KRR-4

Ceres

Pathway to a 21st Century Electric Utility

November 2015



Acknowledgements

Ceres would like to thank the Energy Foundation for a grant that helped make this work possible. Ceres and the author would like to extend their deep appreciation to the experts who generously agreed to review a draft of this report:

- Diane Munns, *Environmental Defense Fund*
- Steven Nadel, *American Council for an Energy Efficient Economy*
- Rich Sedano, *Regulatory Assistance Project*
- Devra Wang, *Energy Foundation*

Dan Bakal, Meg Wilcox and Sue Reid of Ceres made important contributions to this report.

Graphic design by Patricia Robinson Design.

About Ceres

Ceres is a nonprofit organization mobilizing business leadership on climate change, water scarcity and other global sustainability challenges. Ceres directs the Investor Network on Climate Risk (INCR), a network of more than 110 institutional investors with collective assets totaling more than $13 trillion. Ceres also directs BICEP, an advocacy coalition of 36 businesses committed to working with policy makers to pass meaningful energy and climate legislation. For more information, visit www.ceres.org or follow on Twitter: @CeresNews

This report is available online at www.ceres.org

For questions or comments, please contact:

Ceres, Inc.
Dan Bakal
Director, Electric Power
617-247-0700, ext. 113
bakal@ceres.org

About the Author

Peter H. Kind,
Executive Director—Energy Infrastructure Advocates LLC.

Peter is the Executive Director of Energy Infrastructure Advocates LLC, a strategic advisory consultancy focused on public policy supportive of utility and energy sector infrastructure development in a changing energy industry landscape.

Prior to the founding of EIA in 2012, Peter worked for over 30 years in investment banking, with a specialization in utility and power sector finance. Peter's banking experience includes capital markets advisory and transaction execution and strategic advisory services, including merger and acquisition and corporate finance advice. Peter's M&A experience includes all sectors of regulated utility and non-regulated power businesses. Throughout his career, Peter has been actively involved in outreach to regulators and policymakers, including work as an expert witness in regulatory proceedings and forums, presenting at industry and regulatory conferences on financial issues impacting utilities and power producers and in direct outreach on regulatory matters. In 2013, Peter authored a paper on Disruptive Challenges to the utility industry published by the EEI.

Peter's investment banking experience, includes prior experience at Macquarie Group, Bank of America, where he lead the Power and Utilities Corporate and Investment Banking effort, and Citigroup and Kidder Peabody, where he co-directed the Power & Utilities industry teams of each of those firms. Prior to investment banking, Peter worked for Arthur Andersen & Co.

Peter is a Director of the general partner of Enable Midstream Partners, LP, a midstream energy services provider and a Director of NextEra Energy Partners GP, an owner of renewable power generation. Peter is also a Director of Southwest Water Company, an infrastructure fund owned water and wastewater utility.

Peter holds an MBA in Finance from New York University and BBA in Accounting from Iona College. Peter practiced as a Certified Public Accountant until 1981. During 2008 to 2011, Peter was Co-Chairman of EEI's Wall Street Advisory Group.

Table of Contents

Pathway to a 21st Century Electric Utility

Commissioned By: Ceres
Authored By: Peter Kind

As a banker serving the U.S. utility industry for over 30 years, I have long questioned the impact of policy actions and regulatory mandates that threaten the revenue base of utilities and the industry's financial health. In 2013, I authored "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Energy Business," published by the Edison Electric Institute (EEI). That paper presented my views, looking through the lens of an investor, of the challenges confronting the long-term financial viability of the electric utility industry given its present business model.

Since the release of *"Disruptive Challenges,"* the forces outlined therein have continued to develop, particularly the pace of technological innovation and cost-curve improvements. Importantly, electric customers and the policy community have continued to foster key disruptive forces by confirming their support for customer energy supply choice, net energy metering and opposition to increased fixed utility charges. My positions have evolved in order to find solutions that can promote collaboration and alignment of interests.

In reviewing the constantly evolving landscape, I felt that it was important to provide an updated, more holistic perspective that aligns society's needs with the interests of utilities and their customers. In 2010, Ceres made an important contribution to the dialogue with the release of *"The 21st Century Electric Utility: Positioning for a Low-Carbon Future,"* and it seemed a natural fit to collaborate with Ceres on this new paper.

Utilities do an excellent job of what they are mandated to do—provide safe, reliable and affordable energy. Utilities are not going away, because we require them to operate the electric grid, so why not expand the scope of their mandate to manage an environment in which consumers use energy and electricity more efficiently to create customer value and optimize the electricity system for the benefit of all? In this environment, utilities will be incented to maximize customer and system value, as opposed to simply building infrastructure.

Utilities are not going away, because we require them to operate the electric grid, so why not expand the scope of their mandate to manage an environment in which consumers use energy and electricity more efficiently to create customer value and optimize the electricity system for the benefit of all?

Given the importance of revising the utility industry model for the benefit of customers, society and utility investors, this paper is an expression of my evolved views in an effort to find common ground that will support a robust 21st Century Utility model.

Challenges Facing the Electric Utility Business Model

Over the past decade, a confluence of challenges facing the electric utility business model has stimulated active discussion among utility industry stakeholders. The challenges are the result of economic, demographic, behavioral, policy and technology trends, and are not expected to reverse. In fact, they are continuing to gain momentum, particularly the development of new technologies, continued reductions in renewable energy costs, and policymaker support for a revised vision of utility service that supports customer choice.

Utility sector investments, however, continue to trade close to all-time high valuations based on low interest rates. Threats to the utility sector are still in the early stages because customer adoption of new energy technologies remains low, but are growing. Furthermore, customers, rather than investors, are bearing the near-term cost of disruption through increased utility rates, somewhat offset by lower fuel costs.

Once investors begin to experience these challenges as a direct impact on the economic-return potential of their investments, however, the cost and availability of capital to fund the utility sector will suffer. Given that the industry relies on 30-plus-year investment recovery cycles, it is essential that capital deployed today be planned and rationalized to avoid future stranded costs, or investments that are no longer economical.

The current 100-year-old utility business model does an excellent job of keeping the lights on, but it often does not align interests and behaviors or facilitate the policy goals and customer dynamics that exist in 2015. To create the clean, efficient and sustainable energy future that all stakeholders seek, we must revisit the industry model to ensure alignment with customer and policy goals, while also ensuring that utilities and third-party providers are properly motivated to support their customer, societal and fiduciary obligations.

The current 100-year-old utility business model does an excellent job of keeping the lights on, but it often does not align interests and behaviors or facilitate the policy goals and customer dynamics that exist in 2015.

Policy and industry stakeholders in most states are neither proactively addressing industry model challenges from a comprehensive policy perspective, nor seeking the collaboration of all stakeholders to find a solution that benefits all parties. In New York, a closely watched initiative has policymakers defining a future in which the utility role involves managing the grid and acting as a platform provider for third parties. This role is not as investor friendly as utilities would desire. In many states, despite customer and policy opposition, electric utilities are proposing increases in fixed charges, which discourage energy efficiency and impact low-income customers. This lack of progress in stakeholder collaboration is ***not*** in our collective best interests.

While the cost structure of electric distribution utilities is predominantly of a fixed nature (i.e., not meaningfully impacted by volumes or operating variability), utility rate structures have typically authorized a small fixed-charge component. Pursuing an increase to fixed-charge recoveries is a tariff design tool that utilities have actively pursued since 2013 to mitigate revenue risk from the challenges they face.

However, there has been meaningful opposition on the part of customer interests and policymakers to utility proposals to significantly increase fixed charges. The policy of adopting monthly fixed-charge increases has several flaws—principally that such increases would remove the price signals needed to encourage energy efficiency and efficient resource deployment—that need to be considered when assessing alternatives through a lens by which all principal stakeholders benefit. This paper proposes several solutions to address the utility revenue challenge as an alternative to increased fixed charges, such as inclining block rates, reforming net energy metering, use of bidirectional meters, time-of-use rates, accountability incentives and identifying new revenue opportunities for utilities.

More broadly, this paper proposes a **new pathway to a 21st Century Electric Utility system** that creates benefits for customers, policymakers, utility capital providers and competitive service providers.

The key differentiators proposed in the pathway toward a new utility model are as follows:

a) engage the distribution utility to be at the center of integrating resources and stakeholder collaboration to achieve customer and policy objectives through accountability and incentives;
b) shift regulatory oversight to focus on integrated distribution system planning and development of transparent accountability metrics;
c) ensure that utility revenues will reflect incentives (or penalties) earned for accountability of results and new energy management services sourced through new resources, such as an energy management applications store; and
d) pursue cost-effective planning to identify the most efficient technologies to be employed, and cap customer incentives based on the most economical alternatives to achieve policy goals.

The paper first sets the stage by identifying the stakeholders and potential participants in a new industry model, summarizing the objectives and considerations of stakeholders, and reviewing the debate that is playing out, including actions by several of the more proactive states. It then lays out a vision for the 21st Century Utility and identifies foundational principles to support this vision before proposing the pathway. Given that we have over 50 states and districts that regulate our utilities, there will be no one-size-fits-all solution.

This paper proposes several solutions to address the utility revenue challenge as an alternative to increased fixed charges, such as inclining block rates, reforming net energy metering, use of bidirectional meters, time-of-use rates, accountability incentives and identifying new revenue opportunities for utilities.

The **vision** proposed for the 21st Century Utility model is relatively straightforward, and includes:

- enhanced reliability and resilience of the electric grid while retaining affordability;
- an increase in cleaner energy to protect our environment and global strategic interests;
- optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- a focus on customer value, including service choices and ease of adoption.

Instead of maintaining our current policies, which encourage increased electric consumption and capital investments, the objective of the vision is to develop a model that enables customer value and service and achieves policy objectives to position us for the certainties of the future—particularly that the current concentration of fossil fuels in our energy mix poses significant risks to our economy and environment.

Because there is no reasonable threat over the foreseeable future of significant customer grid defection, a robust electric grid is a key component of a 21st Century Electric Utility, and thus, financially healthy utilities will be essential to maintaining and operating the grid.

The **foundational principles** or ground rules to support the achievement of this vision are as follows:

- financially viable utilities are essential to fund and support an enhanced electric grid;
- policymakers must promote clear policy goals as part of a comprehensive, integrated jurisdictional energy policy or 21st Century Utility model;
- commitment to engaging and empowering customers can help them make intelligent energy choices, including third-party engagement and access to necessary data; and
- equitable tariff structures promote fairness and policy goals.

The **pathway** proposed is one wherein policymakers task utilities with the **responsibility for** being at the center of coordinating and accelerating the refinement of our model for a 21st Century Electric Utility, and holds them accountable with penalties and incentives. On this pathway, policymakers will collaborate with stakeholders to develop and authorize the vision for the industry's future for customers and providers. Policymakers will then outline a comprehensive plan to realize their 21st Century Electric Utility model. The proposed pathway shifts regulatory oversight from being administered primarily through periodic rate cases to a forward-looking focus on planning, accountability and financial incentives for results achieved. Tariffs will be refined to address fairness, policy goals and provide price signals, consistent with enhancing system wide efficiency and environmental protection.

Regulators will create incentives and penalties to encourage and hold utilities accountable for achieving transparent goals and metrics to be outlined for measuring progress and success. **Technology innovators and third-party service providers** will collaborate with customers and utilities to create and refine products and services that support policy goals, engage customer interest and integrate efficiently with the grid. **Utilities** will partner with third-party providers and customers to provide reliable, affordable, clean energy in the most efficient way possible. **Customers** will be educated as to opportunities to deploy new services to enhance the value of their electric service and achieve societal benefits, such as reducing their environmental footprint.

Energy efficiency and system optimization, for example, have been an area of focus since the 1980s, and while progress has been made, the majority of customers have not taken advantage of the opportunities that can be realized. The American Council for an Efficient Energy Economy (ACEEE) estimates that a 40 to 60 percent reduction of electricity sales could be achieved by 2050 by harnessing the full suite of opportunities. On a pathway to a 21st Century Utility, we must redouble our efforts to achieve these savings by increasing customer education and giving utilities incentives to engage their customers in adopting such technologies. Because increased efficiency strikes at the revenue base of utilities, the proper incentives must be adopted so that utilities will be at least indifferent to the loss in electricity sales and ideally, be motivated to encourage energy efficiency.

In order to realize the societal benefits of a clean and efficient electric industry, each state should move forward now on a pathway to a 21st Century Utility model. Each state will have different challenges to confront, but the goal would be to develop several robust models that can be tested, compared and refined over time.

The Environmental Protection Agency's newly released **Clean Power Plan (CPP)** provides an excellent opportunity for states to consider their utility model as a component of their CPP compliance plan filings. The CPP sets standards for reducing greenhouse gas emissions from existing and new power plants, and calls for each state to provide its compliance plan by September 2016. The CPP will enable each state to reconsider its energy future and align state compliance plans with a pathway to a 21st Century Utility. Longer-term, customers, society and utility investors will benefit from proactive solutions.

Utilities have remained committed to their historical obligation to provide customers with safe, reliable and affordable service. As dynamics have evolved, society now expects that utilities will confront new priorities, such as protecting our environment and assisting customers in being more efficient with their energy usage. These new priorities challenge utilities' revenue and profitability levels and, thus, utility fiduciary obligations to their investors. A new industry model will need to provide opportunities for utilities to earn a reasonable return while providing society and customers the services they seek.

The proposed pathway shifts regulatory oversight from being administered primarily through periodic rate cases to a forward-looking focus on planning, accountability and financial incentives for results achieved.

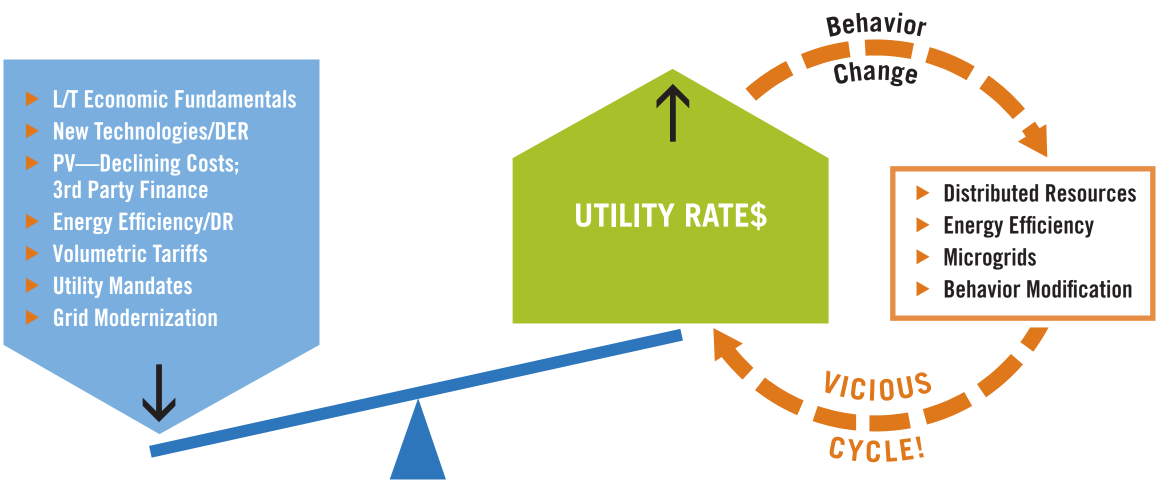
The Case for a 21st Century Electric Utility Model

Disruptive Forces—A Quick Review

Over the past several years there has been active discussion among utility industry stakeholders as to the confluence of challenges facing the industry business model. These challenges are considered long-term forces that are not expected to be reversed, and they encompass economic, demographic, behavioral, policy and technology trends. The principal challenges facing the utility model can be summarized as follows:

- slowing demographic (U.S. population) and economic growth opportunities have reduced electric consumption growth and customers' disposable income levels;
- customer interest in reducing energy usage and environmental impact has gained attention and interest, particularly among Millennials;
- public-policy goals seek to increase energy-efficiency adoption and clean-energy production and to reduce environmental emissions;
- price inflation and costs to deploy new grid technologies are increasing utility capital budgets and requiring increased electric rates (although rate increases have not in general outpaced inflation);
- customers now have enhanced options to save on their energy bills through programs that reward adoption of clean technologies (e.g., solar distributed energy resources combined with net energy metering programs); and
- U.S. regulatory models that are energy-usage based, regardless of load or time of day, constrain prospects for utility revenues and financial health.

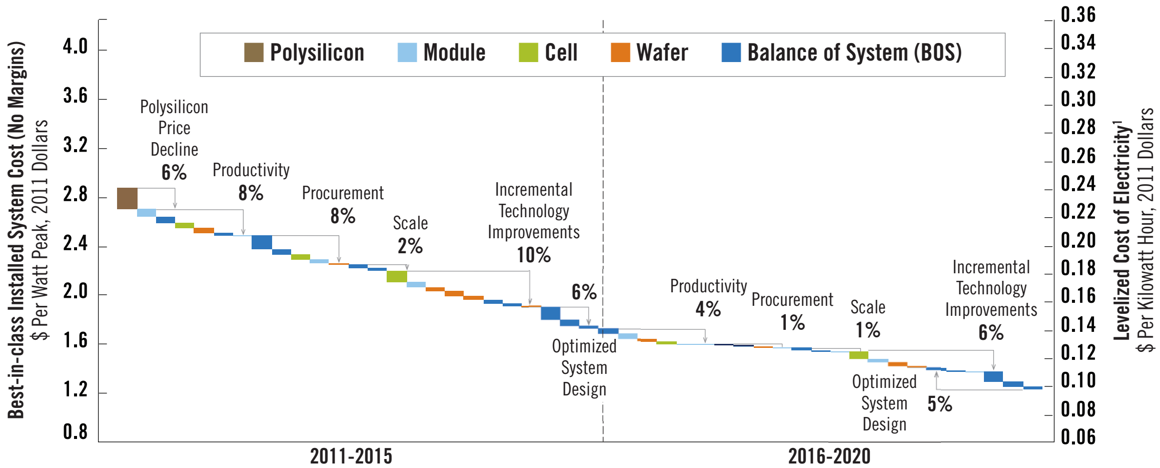
Figure 1: Disruptive Forces—Impact and Feeding of the Vicious Cycle



A confluence of factors are posing disruptive threats to the traditional utility business model.

All of these dynamics are at play while distributed energy resource (DER) economics continue to improve, due to improved technology, market competition and the advent of attractive customer financing options (see **Figures 2 and 3**, below). Left unattended, these challenges encourage a vicious cycle in which customers are motivated to self-generate (such as by rooftop solar) to avoid increasing utility prices, thereby leaving the cost to fund the electric grid to an increasingly smaller group of customers. And yet the grid is essential for DER technologies, particularly rooftop solar, because it allows customers to sell their surplus energy back to the utility. A 2013 study commissioned by the California Public Utilities Commission found, in fact, that due to net energy metering, residential DER customers in California paid approximately 50 percent less toward the fixed cost of providing utility service.[1]

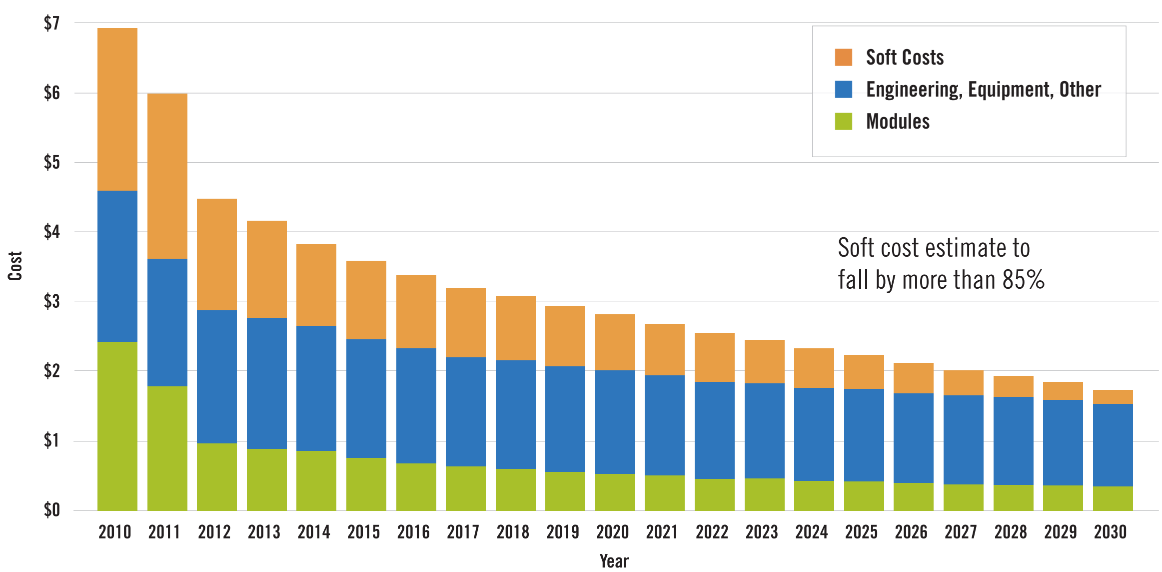
Figure 2: PV Cost Improvements—Innovation and Scale Drive Opportunities



1 Levelized cost of energy; assumptions: 7% weighted average cost of capital, annual operations and maintenance equivalent to 1% of system cost, 0.9% degradation per year, constant 2011 dollars, 15% margin at module level (engineering, procurement, and construction margin included in BOS costs).

Source: McKinsey & Company.

Figure 3: Average USA Price Per Watt for a New Solar System



Source: Bloomberg New Energy Finance.

1 Energy and Environmental Economics, Inc., "California Net Energy Metering Ratepayer Impacts Evaluation," Prepared for the California Public Utilities Commission, October 2013.

Clearly, the electric grid will continue to be essential to virtually all customers for the foreseeable future. In fact, the viable solar rooftop market—after factoring in home ownership, credit scores, locational positioning and suitability and NEM favorability—is currently projected to be approximately 20 percent of US households.[2] Thus, utilities must retain their financial viability to attract the capital required to support the grid. Most investors are not focused on these issues today due to low, though increasing, penetration of DERs and allowed cost recovery of "lost revenues" in future rate cases.

Other disrupted industries have reached the tipping point at which new products and services attain a penetration level and trajectory that challenge the viability of an old-line business and its access to capital. At that point in those challenged industries, financial access and viability are forever threatened. Kodak and Polaroid are prime examples of how disruptive forces (primarily technology in those cases) can destroy a company's financial value and capital access. Given the essential nature of utility services, however, a death spiral for the electric utility industry is not expected in the foreseeable future. Stakeholders must nevertheless be proactive to protect utilities' financial viability, given the industry's vital importance to our energy future.

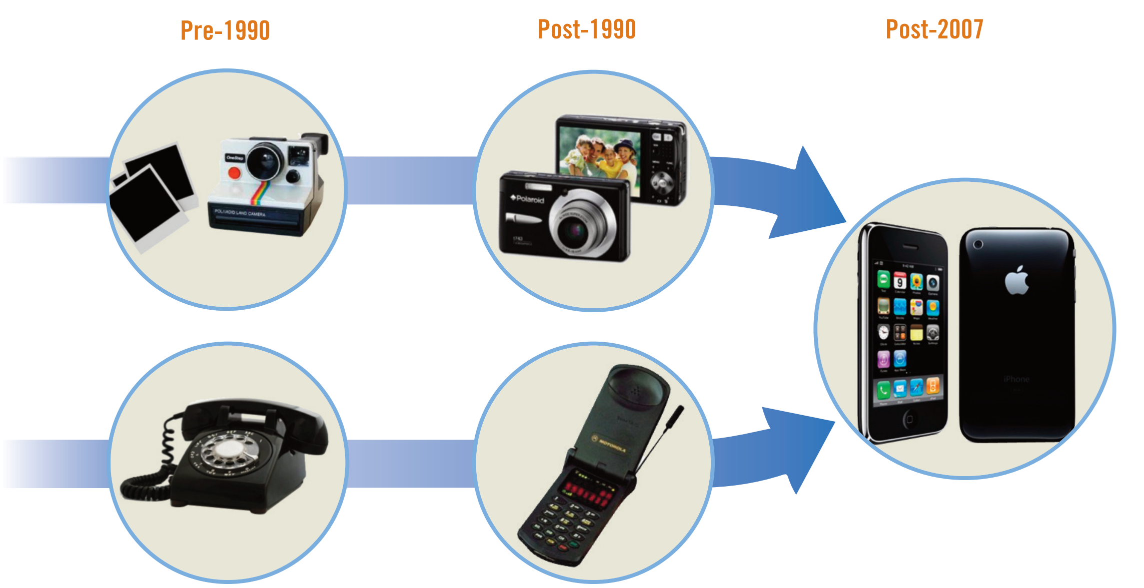
Other disrupted industries have reached the tipping point at which new products and services attain a penetration level and trajectory that challenge the viability of an old-line business and its access to capital.

Value and Future of the Electric Grid

While the "Disruptive Challenges" paper and others have drawn parallels between landline telephone deregulation and the electric utility model, there are important distinctions between the two. First, there is no known technology today by which electricity can be transported from location to location without a wire. Second, for many customers, installing the technology to disconnect from the grid would be prohibitively expensive, and/or they are not in the proper location or lack the ownership control (i.e., rent their homes) to deploy current DER technologies. In addition, industry experts believe there is great societal value created from the development of a robust grid and that grid defection creates barriers to enhancing and maintaining the electric system we require.

While industry discussion, including "Disruptive Challenges," gives examples of a scenario whereby certain customers could disconnect their access to the grid, or new construction could be grid independent (e.g., DER customers with storage), there is no reasonable scenario for **significant** customer exit from the grid for the foreseeable future. The only way to sell power back to the grid is to be connected to the grid. For DER customers, as an example, every time a new

Figure 4: Examples of Technology Disrupting Main Line Industries



2 GTM Research and Vox

customer installs rooftop solar, he or she is likely basing that economic decision on the ability to sell surplus renewable power back to the grid for at least 20 years.

The grid acts to enable the benefits of distributed resources through the sale of electricity to others and to enable commercial opportunities and transactions through the powering of our entire economy. In addition, the grid provides needed backup support for DERs and storage when renewable resources are not functioning or when demand exceeds system capacity. Thus, the electric grid is, and is expected to remain, the backbone of our electric energy system.

A robust electric grid is therefore required to achieve the greater reliability sought by all customers and to enhance access to additional bidirectional power inputs for DER customers. A study by Brattle Group, commissioned by the EEI in 2009, projected that the U.S. electric utility industry will need to invest between $1.5 and $2 trillion between 2010 and 2030 to maintain current levels of reliable electric supply.[3] To maintain a robust, responsive and resilient grid, we must have a structure in place that supports financially healthy utilities capable of attracting the significant capital required. Thus, the question of structuring tariffs to support the grid and other valuable services provided by utilities must be considered (see **Ratemaking and Tariff Design**, page 29).

The Stakeholders in a 21st Century Electric Utility Sector

It is critical that any attempt to develop 21st century approaches seek as much alignment as possible among the key stakeholders involved in electric utility planning. The stakeholders in electric utility debates continue to evolve as priorities and key issues are refined or emerge, and today include residential, commercial and industrial customers, technology sector providers, utilities and their shareholders.

Residential Customers

Residential customers continue to have significant clout in the evolution of policy due to their voting power and large numbers. Groups representing low-income residents and seniors (who often live on a fixed income) tend to have influence because service cost is a high priority. Another prominent voice in the residential class debate is environmental advocacy groups that seek a focus on environmental stewardship and sustainability. Between these groups, there is alignment that aims to avoid high fixed charges for utility services and supports well-designed inclining block rates. Inclining block rates aid low-income residents and seniors by creating a progressive rate tariff: the more you use, the more you pay per unit. From an environmental policy perspective, inclining block rates provide an incentive to conserve energy usage by charging higher rates to the higher energy users.

Commercial and Industrial Customers

Although large commercial and industrial customers lack voting clout, they are active voices in the development of energy policy. Policymakers need to be aware of large customers' impact on the economic growth and vitality of a region; low utility rates will retain and attract them. While energy prices and availability are not the only factors in the drive for corporate competitiveness, large businesses can relocate when the local policy environment does not support their competitive position. In addition, large commercial and industrial customers (including General Electric, Procter & Gamble, Microsoft, Coca Cola and Walmart) are increasingly focusing on their sustainability profiles, including procurement of renewable energy. Thus, as stakeholders consider how to retain current business customers and develop and attract new industries, energy prices, reliability and access to clean energy will be key factors.

Policymakers

Policymakers and regulators tend to be attuned to their most vocal customers, because their voting power controls the ongoing "seat" of the policymakers. It is clear from the wide array of state-mandated renewable portfolio standards, energy-efficiency programs, net energy metering tariffs, and inclining block rates that policymakers are focused on clean energy, consumer choice, efficiency and price signaling. One question this paper seeks to address is whether policymakers are doing all they reasonably can to accelerate programs to optimize these objectives.

Technology Sector Participants

A recent entrant into the energy policy debate is technology sector participants, particularly renewable-energy providers. These entities are selling their products to customers directly and, as a result, customers use less electric service from the utility. While many of these providers understand that they need to cooperate with utilities to provide customers the benefit of their product offering, there is typically no clear, approved path for these competitive providers to partner with utilities to promote their offerings in a way that benefits both the technology provider and the utility. The interaction between technology and utility providers is often adversarial, with the technology provider seeking to sell products that will limit electric sales and thus adversely impact utility revenues. Utilities have therefore been hesitant to partner

3 Brattle Group, ",“In Transforming America's Power Industry, The Investment Challenge 2010—2030," (2009).

with these third-party providers, which have built strong policy advocacy efforts and industry organizations because such activities are essential to their future viability.

Utilities and Their Investors

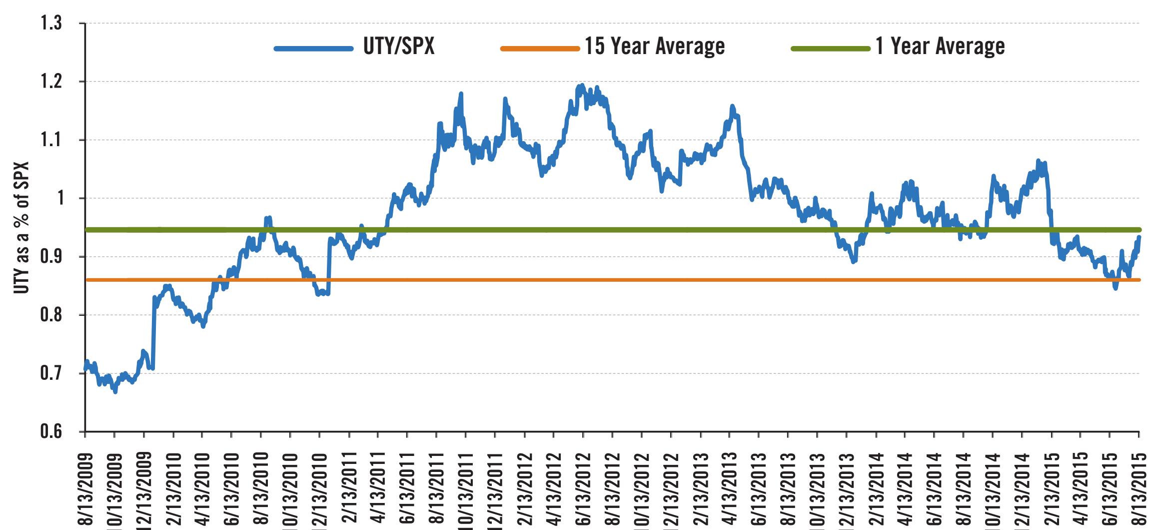
Utilities have many masters, but their principal obligations are to provide safe, clean, reliable and affordable electric service to customers and to earn a fair return on capital invested. Electric utilities generally do an excellent job of meeting customer-service expectations. A comprehensive study, "Exploring the Reliability of U.S. Electric Utilities," showed that reliability, despite extreme weather events, averages above 99.9 percent.[4] However, extreme weather events, such as hurricanes Katrina (2005), Irene (2011) and Sandy (2012) and devastating tornadoes such as Joplin (2011) are examples of the need for enhanced electric grid "hardening" and resilience to protect our citizens and economy.

Achieving an adequate return on capital, in particular in the short term, depends upon selling more energy, because that is how tariffs tend to be structured. Utility boards of directors typically structure utility management compensation programs based on achieving reliability factors and a larger weighting to financial returns. This is more customer friendly than other industries, in which executive compensation is based solely on market share and profit goals. While 25 states offer incentives for efficiency results,[5] these programs tend to offer limited financial incentives to utilities for promoting energy-efficiency services or clean technologies.

For example, while California has been proactive in providing incentives to utilities for encouraging energy efficiency, the incentives reported in 2014 were less than 1.25 percent of pre-tax operating income for the largest California utilities, or less than 0.1 percent in additional return on equity (ROE), after tax. Locating the disclosure of earned incentives in the California utilities' SEC filings is like finding a needle in a haystack. That makes it hard for investors to reflect in their valuation assessment a material, recurring, transparent and timely (in California there is a several-year lag in calculation) incentive mechanism. **While incentives should align behaviors, insignificant and nontransparent levels of incentives will not drive behavioral change and realization of optimal results.**

While utilities are interested in and impacted by the debate on regulatory models, their interactions are challenged by a skeptical policymaker environment, which often presumes that any position by an electric utility reflects a self-serving benefit. Thus, utilities are in a challenging position when it comes to leading or proposing solutions. As a result, utilities tend to be defensive in their approach and often lack the vision or motivation to identify areas where the business model can be enhanced for the benefit of their customers and investors. Instead of arguing for incentive mechanisms, many utilities have been seeking to increase fixed charges, while customers and policymakers are vehemently opposed to such action. An evolved approach would focus on common ground with win4 (i.e. beneficial to customers, policy, competitive providers and utilities) opportunities.

Figure 5: Utilities Are Valued Above 15-year Averages and Comparable to S&P 500

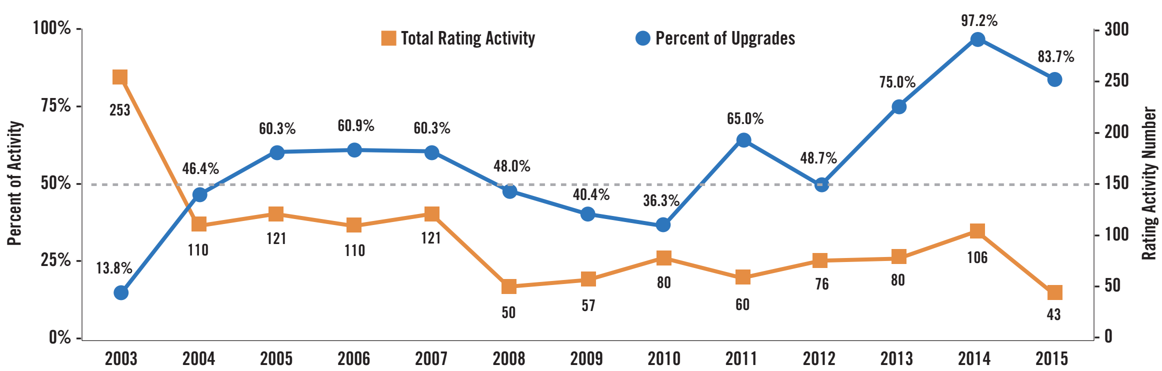


Source: BofA Merrill Lynch Global Research, Bloomberg

4 Larsen, Sweeney, LaCommare and Eto, "Exploring the Reliability of U.S. Electric Utilities," (2012).

5 ACEEE Economy, "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency," June 2015.

Figure 6: Credit Rating Agency Actions Suggest Improving Credit Quality



Source: Edison Electric Institute, Fitch Ratings, Moody's, Standard & Poor's

Utility investors as a group are not interested in change, because the results they have realized from their investments in the sector have provided stable returns. Investors fear that any change could lead to an adverse impact on short-term results and that the defensive investment attributes they have sought—low price volatility, stable economic returns and cash dividend yields—may be compromised. As stated above, boards have structured the bulk of utility management compensation on achieving profit objectives, in addition to reliability performance. Investors are generally comfortable with the transparency of the utility model, despite the argument that the industry model may no longer be appropriate or viable in a changing environment. In fact, utility stock prices today are near all-time highs on a price and valuation multiples basis. Current valuation metric levels (See **Figure 5**) suggest that investors continue to view utilities as an attractive place to deploy capital.

If a material change in business financial performance were to be realized, investors would likely become less sanguine about deploying capital in the sector. But the majority of utility-sector investment analysts and rating agencies see little to be concerned about as long as the penetration rate of efficiency and clean-energy resources is low and regulators allow utilities to recover lost revenues in the near future. In fact, utility credit ratings have solidified over the past several years, particularly distribution utilities, as the economy has stabilized and industry restructuring volatility from the 2000 - 2005 era has been resolved. (See **Figure 6)** So, while short-term dynamics are the current focal point of the investment community, longer-term dynamics should be a key consideration in order to avoid disruption to the utility industry, its customers and our economy.

So, while short-term dynamics are the current focal point of the investment community, longer-term dynamics should be a key consideration in order to avoid disruption to the utility industry, its customers and our economy.

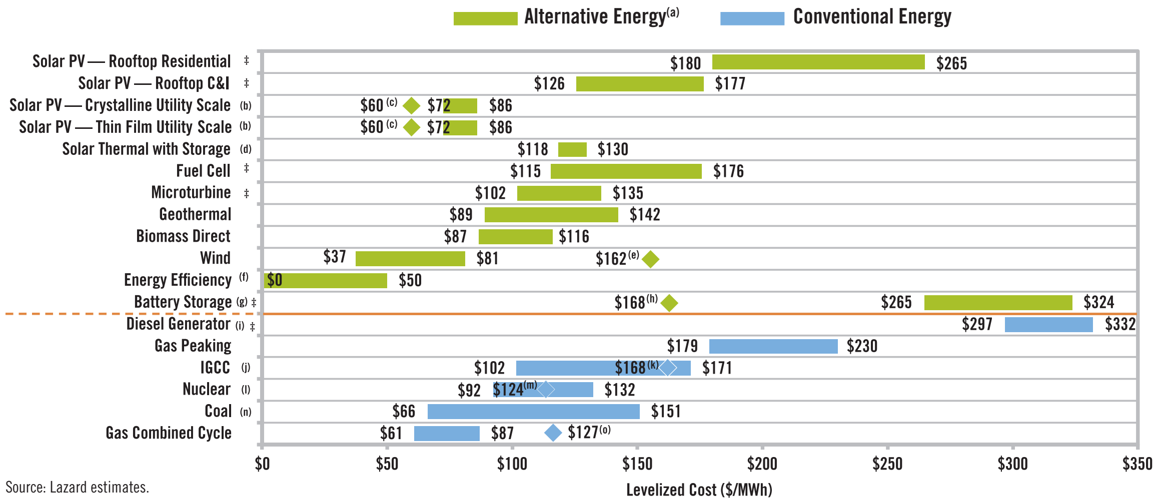
Utility investors, individually or as a group, are not often at the table in discussions on energy policy. Many institutional investors prefer the current utility business model and deal with change by selling the sector or certain investments when it starts to evolve in a way that appears more risky. While some investors, such as those in the $13 trillion Investor Network on Climate Risk (INCR) have become involved in clean-energy policy advocacy, it is still rare to see major institutional investors show up to address a state regulatory policy issue or to support a utility rate case.

Key Stakeholder Issues

Although unanimous agreement on the objectives for a 21st century electric utility industry model is not likely to be achieved, there appears to be solid customer, policymaker and utility support for key foundational objectives for the future industry. Key objectives include improved reliability and resilience of electric service, a cleaner sustainable electric supply and customer cost stability.

Customer cost stability is difficult to achieve in a regulatory construct that seeks (i) usage-based pricing, (ii) customer choice for self-generation of electric supply, compensated by non-DER customers, and (iii) limits on utilities' ability to serve and earn revenues from new 21st Century Utility services. Moreover, the investment required to harden the grid to improve reliability and resilience and provide a cleaner mix of energy resources will increase the cost of

Figure 7: Unsubsidized Levelized Cost of Energy Comparison—September 2017



Source: Lazard estimates.

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under some scenarios; such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.) or reliability-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy generation technologies). Diamonds typically represent expected cost in 2017, wind is for offshore, for more information see https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf

providing service. Despite improving economics, the cost of clean energy, excluding externalities, will likely be more expensive than the current embedded cost of existing generation, because investment and backup capacity are required to support renewable supplies, which are intermittent. Given current utility pricing policies that do not consider externalities, the cost of electric service is expected to increase over time. However, as shown in **Figure 7**, clean energy is expected to become increasingly competitive with traditional fossil energy sources, even before considering carbon costs.

One of the key disputes in the discussion of a 21st Century Utility is the value of clean energy resources. Currently, neither the cost of carbon nor the system wide benefits of a clean-energy strategy, such as reduced system losses and transmission needs, are fully factored into the price of electric power. When the cost of carbon and other externalities are reflected in the cost of energy, the cost to customers will likely prove the long-term benefit of a clean-energy strategy. With the appropriate policies and alignment of interests, the value of electric service can be enhanced. For instance, optimizing our system and the use of energy can reduce the need for new peaking capacity and related incremental infrastructure.

Additional objectives, of policymakers and engaged customers, include system and energy-efficiency optimization, price signals to encourage economic efficiency and optimization, and regional economic growth. But without encouraging efficiency (via technology, price signals and targeted incentives) it will be quite difficult to optimize the primary objective of enhanced price stability, given that incremental resources and investment would be required to support incremental consumption.

J.D. Power, a leading global market-research firm, evaluates industries to understand what drives customer interests, loyalty and retention. In J.D. Power's recent rankings of utility customers, their analysis prioritizes customer attributes as follows:

	Customers	
	Residential[6]	Business[7]
Power Quality and Reliability	1	1
Price	2	4
Billing and Payment	3	2
Corporate Citizenship	4	3
Communications	5	5
Customer Service	6	6

Residential customers are primarily focused on power quality, reliability and price. Interest in new technologies and environmental stewardship does not reflect separate categories but rather contributing factors in the price and

6 J.D. Power and Associates, 2015 Electric Utility Residential Satisfaction Survey.

7 J.D. Power and Associates, 2015 Electric Utility Business Customer Satisfaction Survey.

corporate citizenship scores. Industry data show that a relatively low percentage (less than 1 percent nationally)[8] of utility customers are currently seeking new technologies and choosing to self-generate from renewables. Customers' primary focus today is on reliability and price. A much smaller subset of customers are **proactive** in initiating the adoption of energy-efficiency and clean-energy technologies, but it is a group that is growing rapidly and is expected to increase dramatically in the coming years.

Energy Efficiency—A Growing Opportunity

One of the most significant opportunities to enhance both customer value and environmental benefit is the expansion of energy efficiency. Presently, however, customer adoption rates are low. Policy frameworks need to develop incentives for overcoming the barriers to adoption.

A study by the Edison Foundation on the impacts of energy efficiency at a national level shows that energy efficiency is increasing, but amounted to only 3.4 percent of total 2012 electric energy sales.[9] Another study prepared for the Edison Foundation found that when energy-efficiency savings are combined with enhanced building codes and standards, such savings will increase by 2035 from current levels to 5.6 percent of total electric energy use.[10] While any increase in the adoption of energy-efficiency tools is a positive development, economic studies indicate that much more is achievable and would benefit both customers and the environment.

Leading factors in the low adoption rates for energy efficiency include a lack of general awareness of opportunities (particularly because customers cannot price-shop for another utility provider), lack of trust in third-party providers (due to ongoing "junk" mailings and cold calling), the cost to implement new technologies or services when up-front investment is required, and the fact that customers are too busy to learn about opportunities that may be consistent with their long-term economic and environmental interests.

A recent study by the ACEEE, for example, found that energy-efficiency opportunities could reduce electric sales by 40 to 60 percent from current 2030 forecasts, based on intelligent efficiency advances, zero-net-energy building standards and improved efficiency of appliances and technology. The study also noted significant progress in the energy intensity of our economy from 1980 to 2014 due to structural changes (e.g., the reduction of our manufacturing base) and improved efficiency of appliances, new buildings and electric infrastructure.[11] Thus, the opportunity to increase energy efficiency is substantial, but will require the focus of stakeholders to overcome the barriers to adoption.

The opportunity to increase energy efficiency is substantial, but will require the focus of stakeholders to overcome the barriers to adoption.

Large (commercial and industrial) customers, being focused on profit, are savvier than the residential class as to their awareness of cost-saving opportunities. Given capital availability constraints, however, commercial customers tend to demonstrate high return-on-investment hurdle rates (i.e., short payback periods) to invest capital in activities not directly related to their core product or service offering. This factor limits implementation of investments that would be of long-term benefit to the customer specifically and for society overall.

Policymakers and regulators are clearly intent on promoting customer choice of energy supply and increased renewable energy output. Twenty-nine states have Renewable Portfolio Standards (RPS), 24 states have energy-efficiency resource standards and 43 states have net energy metering.[12] Yet the approach to realizing this objective has primarily relied on customers taking the initiative to investigate new opportunities or responding to utility mailers regarding pilot programs, which are adopted by a very low percentage of customers. While there are many providers in various markets that are seeking to sell their technologies and services, customers often don't know whom to trust in this complex arena and are not familiar with the alternatives.

Why not engage utilities and offer them incentives to assist in accelerating these objectives? Utilities are well positioned to assist their customers in learning about and deploying energy-saving technologies, but they need both increased incentives and accountability for doing so. What we see from the success of smartphone applications ("apps") is that customers want "low-touch" solutions that can be implemented and monitored with ease. While that may not be possible for all services, the smartphone app

8 Solar Electric Power Association, 2014 Power Statistics

9 Edison Foundation Institute for Electric Innovation, "Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures and Budgets", (2014).

10 EnerNoc Utility Solutions Consulting, "Factors Affecting Electricity Consumption in the U.S. (2010–2035),"), (2013).

11 ACEEE, "Energy Efficiency in the United States: 35 Years and Counting," June 2015.

12 ACEEE website, State Energy Efficiency Planning.

is today's gold standard for engaging customer interest. The exciting news is that the advancement of sensor technology and automated controls is creating new possibilities for low-touch efficiency applications in the energy sector (e.g., Nest, a learning, programmable thermostat).

Many observers believe that there is a meaningful aversion on the part of regulators to determining how utilities should be compensated for providing such new services. Thus, the utility role is neglected in favor of competitive industry players, who are *not* well known by customers, to drive this important objective. In fact, there is a logical scenario, to be outlined later, in which competitive third-party providers collaborate and partner with utilities to accelerate the adoption of their products and services.

Finally, although utilities are interested in providing excellent service to customers, they also have a fiduciary obligation to support their investment value by earning a fair economic return on the capital employed in the business. In most jurisdictions, utilities earn revenues based on capital invested, and such revenues are recovered through customer usage. By promoting activities that reduce usage, utilities are working against one of their core missions and their fiduciary duty, which is to earn a fair return on invested capital. Thus, achieving stakeholder objectives regarding energy efficiency and clean-energy technologies may be best accomplished by providing incentives to customers and providers. In most business models, businesses are motivated to sell new services because this enhances revenue. In our present utility business model, utilities realize a "penalty" to their revenues by encouraging the deployment of our current policy objectives, such as energy efficiency. This creates an inherent conflict that requires logical solutions, such as "revenue decoupling," described later, which breaks the link between energy sales and revenue, to align utility and customer interests.

A Vision for the 21st Century Electric Utility

If we could start with a clean sheet of paper, how would electric utility services be structured? We would want to ensure that there was alignment of policy, customer and investor goals in order to structure a product offering that satisfied the best interests of all major stakeholders, a win4. Such a service offering would maintain and build on the high electric reliability we have today; allow customers to benefit from the latest, most economical technologies to optimize the efficiency of their energy service; be environmentally friendly; and seek efficient economic deployment of resources and, thus, capital investment.

Policymakers would seek optimal economic deployment of the system to ensure reliability and capital efficiency. They would expect deployment of resources consistent with local, regional and national environmental policy goals. They would ensure that price signals be provided to customers so that the system was used efficiently to manage systemwide costs (both embedded and future deployment). Finally, policymakers would want to see fairly stable customer prices, to provide customers more certainty and help realize a competitive cost of service that promoted economic growth in the region.

Utilities in this optimal environment would aim to offer a suite of products and services to achieve customer and policymaker objectives, and they would earn at their cost of capital (as deemed appropriate by the marketplace), or be given incentives to earn above it, for meeting these objectives. In a transparent and predictable business environment the cost of capital is lower, and the availability of capital is greater, than for less transparent, less stable businesses. Investors seek a business that offers growth potential as well, because a business without growth offers only a bond-like investment.

Competitive service providers would partner and collaborate with utilities to refine their products, optimize customer-acquisition costs and increase their share of market. In other words, they would partner with utilities to enhance their collective profit potential. To aid in identifying opportunities, competitive providers might avail themselves of defined, non-customer-sensitive electric system data. Policymakers would decide what information could be provided without compromising customer and system security.

How would a 21st Century Utility operate? It would target optimal use of diverse (hydro, solar, wind, biomass, efficiency, demand response, storage and Combined Heat and Power (CHP) renewable or low-cost electric energy resources that would be backstopped and supported by other clean, baseload energy sources. This efficient deployment of renewables, consistent with a utility cost-effectiveness plan, would seek the most economical and location-efficient technology to provide the best resource base for the benefit of the entire system. For example, in addition to residential rooftop PV solar systems, which do not consider optimal location or technology efficiency, the resource base would include a significant component of DER, community or utility-scale solar, intentionally located to enhance grid and system efficiency. The system would look to include efficient deployment of demand response and microgrids in those areas where reliability was of paramount importance (e.g., regions with high concentrations of hospitals, senior centers and schools) to protect them from weather and other emergency events.

This efficient deployment of renewables, consistent with a utility cost-effectiveness plan, would seek the most economical and location-efficient technology to provide the best resource base for the benefit of the entire system.

Energy Management Applications Store

Over the past several years we have witnessed explosive success and customer interest in software applications that integrate with smartphones and tablets to provide easy and fun access to powerful software tools. These apps provide an array of services and information at the touch of a button. Why not create a customer-focused energy management application page, or "store," that would allow customers to explore a range of product and service alternatives to save energy and money? The objective of such a store would be to:

1) introduce an available product or service alternative;
2) provide information to educate the customer;
3) highlight quality vendors to provide the service, as appropriate;
4) provide click-through to order the product, arrange for an estimate or get further information; and
5) monitor results from using the product.

Ease of access to robust information and service ordering would be effective in engaging and empowering customers. Customers could be offered demand response, load management and time-of-use products that could be operated from their smartphone or other device. "My Dashboard" icons could support "shadow billing" to assess the potential savings from efficiency applications and other service opportunities. Customers' ability to arrange for the installation, operation and oversight of these services would be as easy as the touch of a button. Their total savings would be presented on the app so that they could see the benefit of their actions and understand how their usage and savings opportunities compare to their neighbors. This vision is not futuristic, because such tools and products exist today. The 75 percent of Americans with smartphones (expected to reach 80 to 85 percent by December 2015) or 87 percent with Internet connections would be able to access these services easily.[13]

The question remains: Who is best positioned to host the energy management app store—the government, the utility or some other sponsor? There is no reason that such an approach need be exclusive to one provider. The challenge is how to achieve the most traction from such an effort and create an environment in which customers have confidence that the information is objectively presented. Given an objective of increasing customer adoption of new technologies, utilities appear best positioned to be a logical host of this application store. They have the ability to provide usage data and objectively present information on services. In addition, utilities are best positioned to track and aggregate results of products and services to present to current and potential customers.

Policymakers would have to decide how to compensate utilities for providing this service. The Apple model is worthy of consideration. Apple hosts the App Store on its system and earns a fee from application developers (e.g., competitive energy solution providers) when users download apps. In the energy management model, third-party providers could compensate utilities for each customer click or purchase of a product or service. This model would likely result in a cost-effective tool for third-party providers to reach customers.

Importantly, the energy management application store by itself will not be sufficient to drive results without continued efforts by third-party providers to develop new efficiency technologies and by policymakers and utilities to design programs and customer education initiatives.

Figure 8: Energy Management Applications Store

13 comScore, "U.S. Smartphone Market Share Report,", February 2015.

Incentives would optimize expenditures and thereby moderate customer rate increases to help reform the utility model and manage behaviors. By realizing efficiency and system-load optimization, and considering tools such as the UK's Totex (see **Experiences in Selected States and the UK**, page 25), we should be able to moderate capital investment levels. For utilities, these incentives will offset reduced growth opportunities for investors and, most important, encourage the achievement of customer and policy objectives.

The challenge is that we are not starting from a clean slate, and while we have an excellent quality of essential utility service, the shift to the 21st Century Utility model requires complex transitions that will be heavily debated by stakeholders.

Examples of such transitional issues include:

- phasing in new clean-energy resources while phasing out less clean resources;
- phasing out current subsidy structures for DER users to an economic-value-driven incentive model;
- enhancing customer engagement in pursuit of optimal use of efficiency resources through continued focus on awareness, education and customer incentive programs; and
- regulatory reform to align interests, incentives and metrics for achieving accountability of results.

In order to achieve these goals, we need to create a transition plan that embraces the end-state vision. For that we need policy leadership, clear goals, alignment of interests and accountability.

The vision for the 21st Century Utility can be summarized in four simple points:

- enhanced reliability and resilience of the electric grid while retaining affordability;
- an increase in cleaner energy to protect our environment and global strategic interests;

Technology Game Changers

Although it is a mature industry, the electricity sector has become increasingly dynamic. New forms of technology are in development that will significantly shape the future of the utility business. Given the large capital investment required to fund this sector, and its essential and pervasive involvement in our communities, an important consideration to factor in to the development of the 21st Century Utility industry framework is how customers and utilities will deploy and address new technologies, including those on the horizon that have not yet achieved commercial viability.

Policy will be an enabling driver of many of these game changers. Policymakers should be proactive in considering how best to accelerate each of these opportunities in a 21st Century Utility model to maximize their potential economic and environmental benefits. Potential game-changing technologies such as the following could dramatically reshape the utility business.

- **Grid scale and customer-owned battery storage units** allow electricity to be stored when not required for immediate use and thereby dramatically enhance the value of intermittent resources, such as solar and wind power. They also allow customers to buy power from the electrical grid when prices are lowest and use their own energy at more expensive times. This is a technology-driven opportunity.
- **Electric vehicles** create potential for substantial additional electric demands (expected to be off-peak) for charging batteries and could discharge energy back into the system when the charge has more value as a pure electric energy source. This is a technology-, policy- and customer-preference-driven game changer that could significantly reduce pollution from the transportation sector.
- **Combined heat and power** standards for all large, continuously deployed energy loads (hospitals, hotels, prisons, etc.) optimize BTU consumption by leveraging waste heat into electric energy and steam-heating loads. This is a policy-driven game changer using incentives.
- **Enhanced building standards** can promote energy efficiency and strive to reach net-energy-neutral status. This requires policy to mandate that new construction and remodeling achieve higher efficiency standards. According to a study prepared for the IEEE , aggressive building codes and standards would achieve a 17 percent reduction in electric usage by 2035.[14]
- **Appliance standards** can compel all new major energy-using appliances to operate at best-in-class efficiency levels and support Internet adoptability for purposes of controlling technology use. This is a policy-driven game changer.
- **Big data analytics** can be leveraged to enable intelligent efficiency technologies. This is a technology- and policy-driven game changer.
- **Cost-effectiveness planning protocols** can be applied, both for resources and systemwide, including renewable adoption, promoting the most efficient resources to provide systemwide benefits. This is a policy-driven game changer.

Most of these game changers will allow for more efficient deployment of system resources (e.g., storage, CHP, building and appliance standards). While electric vehicles will increase off-peak electric consumption, they offer the opportunity for storage optimization. All of these listed items will require incremental capital investment, either on the grid or behind the meter.

14 EnerNoc Utility Solutions Consulting, "Factors Affecting Electricity Consumption in the U.S. (2010—2035)," (2013).

- optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- a focus on customer value, including service choices and ease of adoption.

Reliability and Resilience

Few question the priority and importance of enhancing the reliability and resilience of electric service. While our electric system is highly reliable, recent weather events and the reliability needs of our increasingly technology-dependent economy are ample proof that we require exceptionally high reliability and resilience to fuel our economy. As in most areas of strategic importance, we cannot just maintain the status quo, but must be committed to continuous improvement of our electric system to support new technologies and the competitiveness and growth of our economy.

Increased Clean Energy

Most Americans believe that preserving a clean environment and addressing climate change are essential priorities. Gallup polling shows that only 24 percent of Americans have no concerns as to the quality of the environment (which is down from 29 percent in 2010).[15] Opposition to developing a cleaner energy mix tends to highlight the near-term economic impact (jobs and costs to customers), but momentum is clearly building toward a cleaner energy mix. In support of a clean energy future, (i) 36 states plus D.C. have either renewable portfolio standards (29 states plus D.C.) or renewable portfolio goals (7 states), (ii) 23 states have energy efficiency resource standards, and (iii) the US EPA recently released the Clean Power Plan (which aims for a 32 percent reduction in greenhouse gas emissions by 2030).[16]

Optimizing the use of our energy infrastructure will enhance our economic growth potential by increasing customer discretionary income and reducing costly energy emissions.

Optimized Energy System

Optimizing the use of our energy infrastructure will enhance our economic growth potential by increasing customer discretionary income and reducing costly energy emissions. Optimization of resources includes efficient energy consumption, spreading usage to off-peak periods and reducing the need to invest in incremental energy infrastructure. In doing so, current and future costs of electric service can be proactively managed to enhance value for customers. System energy loads should be optimized, not simply individual customer energy loads. For example, if there are better ways to enhance the efficiency of the grid (vs. behind the meter), all customers benefit equally from this investment. Examples include community solar and grid-level storage, as compared with customer DER application of such technologies. *This is not to suggest that we mandate one renewable resource over another, but that we pursue the most cost-efficient energy sources, either through new-construction plans or by capping incentives on DERs consistent with the most cost-effective clean-energy options.*

Con Ed's Brooklyn-Queens Program

An interesting example of deploying innovative solutions to achieve the goals of a 21st Century Utility is Con Ed’s Brooklyn-Queens Demand Management Program (BQDM). The BQDM seeks to reduce demand by 52 megawatts via customer-side and utility-side solutions in order to avoid spending $1 billion on a new substation and related electric infrastructure. This initiative will provide incentives to participating customers and to Con Ed and will result in lower utility rates for all customers.

Customer Value

This is a new area of focus for utilities. Prior to DER and efficiency applications, utilities were responsible for meeting system needs, and customers were viewed as “ratepayers.” When customers have alternatives, service providers must focus on providing customer value. Utilities are in the process of transforming to customer-focused organizations with an expanding choice of energy technology options. This is a work in progress, and many utilities may not understand the significance of this change. The focus on customer value also includes ease of product adoption. We live in a complex world in which many interests compete for our time. Value to customers is not just about product quality and cost of service, but includes making it easier for customers to learn about and, if appropriate, adopt alternatives.

To build such an industry, we will need foundational principles to support the vision and a pathway to reach it.

15 Gallup, Gallup Social Series: Environment, March 2015.

16 ACEEE website, State Energy Efficiency Planning.

Chapter 3

Foundational Principles to Support a 21st Century Electric Utility

A durable building or organization requires a strong foundation to support its structure. The prior section outlined the vision for a 21st Century Utility industry, but we cannot create this without solid foundational principles, which are as follows:

- financially viable utilities are essential to fund and support an enhanced electric grid;
- policymakers must promote clear policy goals as part of a comprehensive, integrated jurisdictional energy policy or 21st Century Utility model;
- a commitment to engaging and empowering customers can help them make intelligent energy choices, including third-party engagement and access to necessary data; and
- equitable tariff structures promote fairness and policy goals.

Financial Viability

Enhancing our electric grid to achieve our reliability objectives will require significant investment. The Brattle Group estimated that $75 to $100 billion per year (in 2009 dollars) will be required to maintain reliability levels. The industry, however, has operating income of $30 billion per year before paying dividends, which means it needs access to external capital to raise the significant funds (in excess of $50 billion per year) to support the existing business and make the required future investments. Accessing capital of this magnitude requires investment-grade credit ratings (BBB- or above, using Standard and Poor's parlance). The better the financial health of the utility, the larger its potential audience for capital and the lower the cost of capital realized. Thus, financially healthy utilities are a key foundational component of a 21st Century Utility model. Importantly, financial health is built over many years of experiencing a transparent and durable operating environment, with consistent policies and financial performance.

Clear Policy Goals

The utility industry cannot evolve without rules and regulations that support the desired evolution. Thus, policymakers must assess the landscape and create, through active interaction with key stakeholders, clear policy goals and a program to achieve them. Each jurisdiction will need to fully explore the interests of stakeholders, the policy objectives already in place and the impacts of proposed policy shifts on their stakeholders. The objective is to develop a comprehensive and integrated set of policies that drive toward the desired outcomes while accounting for constraints to reaching the vision. Although several states are exploring the opportunity to refine their utility model (see **Experiences in Selected States and the UK**, page 25), no state to date has implemented an integrated, comprehensive set of policies, with a timeframe and plan to reach an objective. Without a comprehensive set of policies and a plan, a jurisdiction may have a variety of programs, some mandated and others aspirational, to refine utility services. But such plans require appropriate incentives and accountability as a comprehensive package to drive reform.

Customer Empowerment

A commitment to empowering customers to make intelligent energy choices may seem obvious, but it requires proper alignment of stakeholder interests. Traditionally, utilities have been motivated to sell electricity, not support reduced consumption or investment. We need to remove the model bias that promotes traditional utility financial value and create an environment in which all stakeholders are aligned and benefit from behaviors consistent with the vision. When shared interests are recognized, we have an opening for an environment that supports customer value creation, including promoting actions and tools for customers.

Equitable Tariff Design

Utility tariff structures will be a key component of the strategy to achieve a 21st Century Utility. Tariffs are central to both customer value decisions and recovery of revenues to support utility financial health. The development of tariff structures that support policy-driven objectives and that are fair to all customer classes is a key area of debate. In a model that focuses on efficiency and cost of service, inclining block rates have been a favored tool to mitigate excessive energy use. The problem for utility revenues is that this rate structure feeds customer choice dynamics that reward DER selection and transfers costs to non-DER customers. In the discussion of tariffs that follows, a package of solutions is proposed that is intended to encourage policy goals, fairness to all customer classes, systemwide cost optimization and utility financial stability.

Planning to Accelerate and Coordinate Industry Evolution

The U.S. has more than 50 state/district regulatory authorities overseeing investor-owned utilities, which represent over 70 percent of the U.S. electric industry.[17] To enable the industry to evolve, states have generally taken the approach of setting goals (e.g., RPS) and programs but rely on utility mandates or the competitive marketplace to innovate and provide solutions directly to customers, with the expectation or hope that customers will engage in these products and efficiency behaviors. If we rely on the marketplace to support the future of electric services, the most successful competitive market participants will win, but they may not be the most efficient for customers or society overall, as evidenced by the relatively low penetration of and energy savings from efficiency technologies.

To drive our electric energy future so as to optimize our finite resources (energy and capital), it seems appropriate for policymakers to proactively develop a comprehensive vision and plan for each jurisdiction's energy future. The objective would be for us to take charge of our direction and accelerate the efficiency of activity, and thus mitigate any waste of energy and capital through the transition of the plan to the desired end state. The components of a statewide energy or 21st Century Utility plan would include:

- **vision**—how we expect customers to use and manage their electricity needs in the future;
- **objectives**—comprehensive, integrated policy positions to achieve the vision, including the approach to deploying renewables, storage, DER and microgrids;
- **defined goals**—providing metrics and timeframes for achieving progress toward the realization of the vision;
- **clear participant roles**—who will be held accountable for driving the vision, and how customers, policymakers, utilities and competitive service providers will interface and cooperate;
- **incentives**—quantifying the appropriate level and approach to allocating financial incentives to stakeholders to accelerate and realize the vision;
- **accountability**—ensuring the realization of the vision through metrics, incentives and penalties; and
- **feedback loop**—how often the plan will be evaluated to reflect changing market dynamics and opportunities.

Given their scale, presence and interaction with all stakeholders, particularly customers, utilities appear to be the only logical entity to coordinate and be held accountable for the execution of a 21st Century Utility model and the realization of milestone goals.

Essential to the evolution and acceleration of a 21st Century Utility is the education of customers on the opportunities and benefits of optimizing their energy use (reducing use and/or moving load off-peak), deploying alternative technologies to optimize usage and offering assistance in adopting such new services. The more effective the education and ease of effort to adopt and utilize new services, the more likely that customers will be receptive.

While utilities have offered energy-efficiency programs and services for years, the Internet and smartphones are accelerating customer education and energy optimization. Smartphone apps turn what used to be low-priority chores into fun ways to be productive and share success and opportunities with friends. So although utilities have been involved with efficiency in the past, technology is driving exciting new products and services, and smartphone deployment is making it easier to adopt and manage these new technologies.

17 EEI, EEI website.

The Clean Power Plan

The EPA's newly issued CPP offers states an excellent opportunity to develop their energy strategies for achieving a 21st Century Utility business model. Issued in August 2015, the long-awaited rule governs performance standards for greenhouse gas emissions from existing and new power-generation sources. The CPP outlines the first national standards for CO2 emissions from power plants and seeks to reduce emissions from the power sector by 32 percent in 2030 from 2005 levels. Among its benefits, the CPP aims to improve health by reducing pollutants, supports clean-energy innovation and provides the foundation for a national climate change strategy. Compliance commences by 2022, with phase-in completed by 2030.

While lawsuits have already been filed against the rule, when implemented the CPP will be based on three building blocks: (i) improved performance of existing coal-fired power plants, (ii) substitution of natural gas power generation for coal-fired capacity; and (iii) increased renewable generation to an estimated 28 percent of our energy mix by 2030.

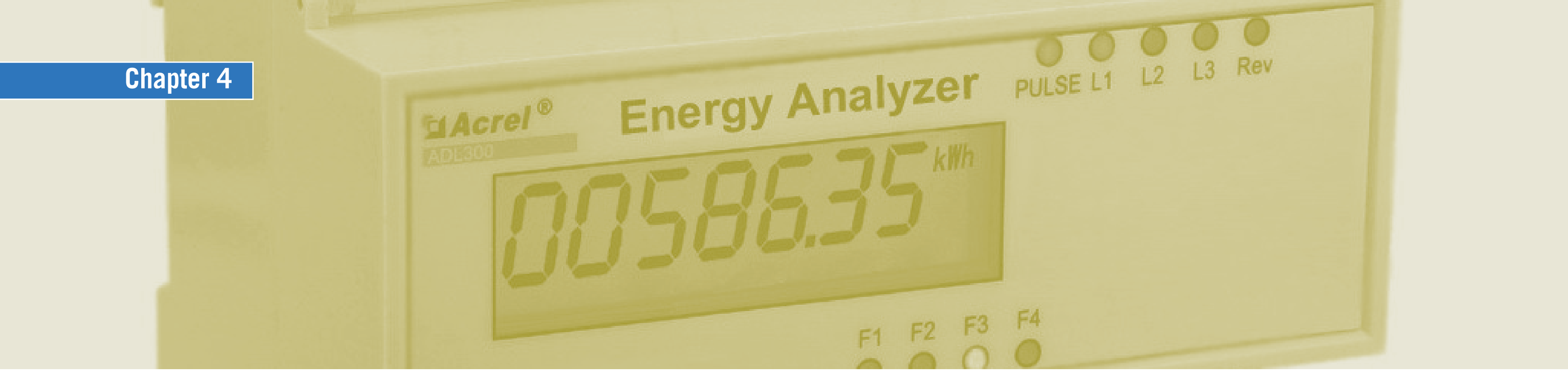
Each state is responsible for developing and implementing a plan that ensures compliance through the phase-in. States have the option to implement plant-specific performance plans or a statewide portfolio approach. While end-user energy efficiency is not a formal building block in the rule, it is allowed as a compliance option. States can also join together to develop multistate solutions, such as the Regional Greenhouse Gas Initiative. The rule calls for state plans to be filed by September 2016, with the potential to seek extension until September 2018.

While the CPP provides significant flexibility to states, the rule will likely lead to reduced coal-fired power generation and a significant expansion of renewables to achieve the targeted CO2 emission reductions. For renewable power generation to grow from 13 percent of our power mix in 2013 to 28 percent in 2030 will require a dramatic increase in renewable-energy capacity and investment.

States will likely consider multiple strategies to encourage an increase in renewable energy, including expansion of RPS mandates to support their CPP implementation plans. Based on projections developed from Energy Information Administration (EIA) data, the renewable capacity required to generate the 2030 goal could stimulate up to 350GW of incremental renewable capacity. This level of capacity expansion will require all forms of renewables to be adopted, but utility-scale renewables will likely be a very large component of the compliance requirement, given their scaling potential and economic advantages.

The timeframe set for state CPP compliance plans provides an excellent opportunity for each state to develop its energy strategy in alignment with the 21st Century Utility model proposed in this paper.

The timeframe set for state CPP compliance plans provides an excellent opportunity for each state to develop its energy strategy in alignment with the 21st Century Utility model proposed in this paper.



The Pathway to a 21st Century Electric Utility

Stakeholders will likely agree on the vision and foundational principles to support a 21st Century Utility model, but the way to achieve it will be more heavily debated. This paper introduces a pathway for accelerating the realization of a 21st Century Utility by setting clear policy direction, assigning accountability for results and shifting the focus of regulatory oversight from litigated rate proceedings to forward planning and accountability with incentives and penalties. The following pathway points are not an á la carte menu of choices but are intended to be a combined package of actions to support and integrate realization of the vision.

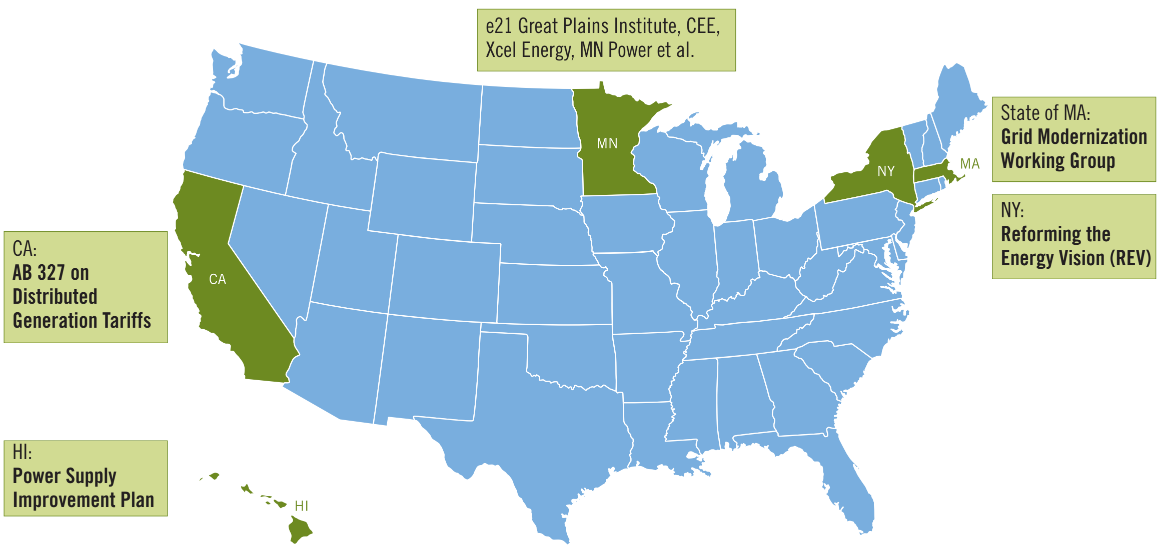
- State policymakers pursue legislation to outline the model for a 21st Century Utility, to include:
  - providing environmental, RPS, energy-efficiency, demand response and peak-load management objectives, including transitional targets;
  - refining building standards to address new construction and major modifications to support efficiency and environmental footprint goals (e.g., California Zero Net Energy Plan for new construction);
  - accountability metrics for managing the transition to the vision;
  - reform of the regulatory oversight approach to focus on planning and accountability oversight; and
  - outlining the role by which distribution utilities will be authorized to participate, including the potential for service revenue and behind-the-meter asset ownership.
- Regulatory reform is enacted to support efficient resource deployment and accountability:
  - multiyear integrated transmission and distribution system planning process, including defining the value and cost-effectiveness of renewable options;
  - transparent and sustainable accountability metrics to be set, based on customer and policymaker objectives;
  - transparent and sustainable incentives (and penalties) for accountability as to realization of policy objectives;
  - multiyear rate proceedings to target customer focus and shift of resources from regulatory administrative proceedings to planning and results accountability; and
  - structure of utility revenue potential for integrating new customer services and potential for ownership of DERs, including revenue requirement implications.
- Tariff structures are refined to support price signals and financial viability requirements, including:
  - inclining block rates to encourage efficiency and signal incremental cost of new resources;
  - bidirectional meters installed for all DER customers;
  - transition to highest economic value renewable rate:
    - most economical option to meet RPS, adjusted for transmission and distribution investment, line losses, system reliability and emissions avoidance value, and
    - timing of transition and grandfathering of existing DERs;
  - demand response to be bid into capacity planning to encourage load resource optimization; and
  - time-of-use rates to be implemented to manage peaks and enhance system optimization.
- Utilities are empowered and accountable for managing the transition, and are:
  - held accountable for controllable results in achieving a 21st Century Utility;
  - encouraged to lead the integration of new technologies and given incentives to achieve results, as deemed appropriate;
  - responsible for educating customers on new energy management alternatives; and
  - the potential owners of renewables, new technologies, or DERs, as addressed in statewide energy or 21st Century Utility plans.

Experiences in Selected States and the UK

States with high electric prices, locational DER opportunities or grid reliability challenges will likely take the lead in pursuing 21st Century Utility proceedings and, hopefully, implementation programs. Clearly, states will develop policies and strategies that reflect their unique circumstances regarding policy, system resource issues, locational opportunities and energy costs. Many states will learn from first-mover jurisdictions that are pursuing a 21st Century Utility model in a comprehensive manner.

While practically every state has addressed specific issues related to energy supply and efficiency programs, few have developed a comprehensive framework for engaging the utility of the future. California and New York have been the most proactive in leading change in their markets. Also worthy of note is the Revenue = Incentives + Innovation + Outputs (RIIO) model in the UK and how it has addressed the alignment of customer, policymaker and utility interests. In Minnesota, policy advocacy and utility interests have proposed an interesting paradigm to develop the electric utility model and are in the process of collaborating with state policymakers to discuss the proposed framework, referred to as the e21 Initiative.

Figure 9: Responses to Evolving Electric Utility Models



Source: Great Plains Institute, July 2015.

California has led efforts to reform its utility model, dating back to an aggressive Public Utilities Regulatory Policy Act implementation program in the 1980s and its groundbreaking 1994 industry-restructuring docket. However, the California energy crisis of the summer of 2002 illustrated that not all that has been tried in California has met with success. Still, California has led with its aggressive implementation of renewables through its RPS (now seeking a 50 percent renewable mix by 2030), attracting both rooftop and utility-scale renewables, and energy-efficiency spending (about 30 percent of U.S. spending).[18] California also leads on incentive programs for utilities to achieve efficiency savings and programs to enhance energy-storage technologies, though the incentives for efficiency adoption are modest relative to the amount needed to drive significant organizational focus and strategy.

Currently, California is mandating that distribution resource plans be provided by each utility, with a focus on better integrating DERs into the grid. However, California has not gathered its array of programs into a comprehensive 21st Century Utility model, and is only beginning to unleash the full power of its nearly statewide advanced metering infrastructure, including meaningful residential customer application of time-of-use rates. Policymakers are facilitating change through mandates, due to California's high electric prices and their willingness to allow cross-subsidies among and between customer classes. Such mandates raise questions as to the fairness of benefits to all customers, given the small but growing percentage of customers who take advantage of market opportunities, such as rooftop solar rewarded with high net energy metering buy-back rates.

18 Edison Foundation Institute for Electric Innovation, "Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures and Budgets", (2014).

New York has been the most active in pursuing a comprehensive solution to a reformed utility model. The New York state proceeding Reforming our Energy Vision (REV) intends to promote more efficient use of energy, including increased penetration of renewables and DERs. It also intends to promote markets to drive greater use of new technologies for energy management. The objective is to empower customers by providing more choices for managing their electric consumption. Utilities, under REV, will be tasked with operating the grid and acting as the distribution-service platform provider, integrating market solutions into the grid. The New York Public Service Commission (NYPSC) is considering tariffs and incentives to better align utility interests with achieving the commission's policy objectives. The Staff of the Department of Public Service issued a white paper[19] in July 2015 proposing future incentive opportunities for New York utilities, including market-based earning opportunities from new grid-related services and incentive mechanisms for performance consistent with goals. The REV initiative is a work in progress.

Neither California nor New York has yet created material, timely or transparent incentive frameworks to move utilities to revise their approach to customer engagement, or otherwise taken a leadership position to encourage large percentages of the customer base to more proactively optimize energy consumption. In New York, that is starting to change. Con Ed's BQDM Program, discussed earlier, is a recent example of the NYPSC approving an innovative solution that does provide for incentives to the utility.

In California, the incentives available two years after the reporting period yield less than 1.25 percent of utilities' operating income.[20] This level of incentive does not motivate major corporate strategic reassessment of operational, financial and compensation strategies. In addition, the programs in California and New York do not promote the most efficient use of DERs, but encourage the marketplace to adopt DERs, at the same time discouraging the utilities from investing in them by offering attractive net energy metering incentives.

Minnesota's e21 Initiative is an interesting and important collaborative effort to develop Minnesota's 21st Century Utility. The effort is led by the Great Plains Institute, an energy policy advocacy group, and involves Minnesota's investor-owned electric utilities and several national energy policy groups. The initiative proposes a comprehensive framework for a 21st Century Utility and regulatory oversight approach. The Phase I report, issued in December 2014, includes the following recommendations:

- reward utilities for delivering customer value with reduced reliance on a capital investment–driven model;
- align the utility model with state and federal policy goals;
- enable the delivery of services that customers value;
- fairly value grid and DER services;
- focus on economic and operational efficiency of the entire system;
- reduce regulatory oversight–related administrative costs; and
- facilitate innovation and implementation of new technologies.

e21 proposes performance-based ratemaking as an incentive to utility performance, consistent with multiyear integrated system plans that focus on DER deployment and reducing costs through system wide efficiency measures. The initiative seeks to establish multiyear rate programs to shift the regulatory oversight focus from rate-case preparation and deliberation to forward planning.

If the system can benefit from efficiencies related to operating versus capital expenditures, the utility will earn a return on a component of such efficiency savings while the customer benefits from a lower cost.

The e21 Initiative, while in its early stages, represents a comprehensive and collaborative approach to pursuing a 21st Century Utility model. Unlike New York's REV, this initiative is more robust in that it provides a larger role for utilities to engage with customers and it outlines how regulatory oversight should evolve. For the initiative to move forward, policymakers will need to endorse the framework outlined. How this initiative is ultimately received by Minnesota policymakers, and the full range of public process participants that engage in the discussion, will shed light on the prospects for policy-led collaboration toward a new utility model, in Minnesota and nationally.

The **United Kingdom's RIIO** model is encouraging to consider for its impact on ratemaking solutions. The RIIO model builds on the UK's prior approach to determining revenue. It will create eight-year periods for price review, under which utilities have the opportunity to realize operational efficiencies, subject to accountability metrics, and given incentives to consider operating investments that replace or defer capital investment (known as Totex, or total expenditures). Totex was structured to address the inherent utility bias toward capital investment (rate base) by capitalizing and allowing a return on, and of, investment of certain operating expenditures that avoid or defer less economical capital investment. The concept is to focus on optimizing total system expenditures. If the system can benefit from efficiencies related to operating versus capital expenditures, the utility will earn a return on a component

19 State of New York Department of Public Service, "Staff White Paper on Ratemaking and Utility Business Models," July 28, 2015

20 SEC Form 10-K for Edison International and PG&E Corporation

of such efficiency savings while the customer benefits from a lower cost. The criticism of RIIO is that significant regulatory proceedings, costs and ongoing oversight are required to approve and execute on a RIIO planning period. So, while the RIIO model may not be appropriate for many U.S. states due to the significant administrative burdens created for policymakers and utilities, components of RIIO, such as multiyear regulatory review periods and Totex, are worthy of consideration for implementation.

Developing an Accountability and Incentive Framework

The utility model we operate within today is highly regulated and mostly backward looking in its approach to regulation. In an ideal world, policymakers would outline their policies and develop accountability metrics to monitor and evaluate utility performance. Instead of mandating and overseeing countless proceedings as to utility performance, a strategy could be employed by which reasonable accountability metrics were tied to meaningful incentives and penalties that would lead utilities to focus on achieving best-in-class performance. Since U.S. utilities for the most part already provide best-in-class reliability of service, new accountability metrics would focus on achieving performance toward a 21st Century Utility framework. Examples of potential accountability metrics, focusing on customer and policy goal realization and the transparency and sustainability of such goals, are as follows:

- **reliability**—percentage of hours of uninterrupted electric service and percentage and number of annual outages impacting customers;
- **service**—range of customer energy solutions offered, number of customer calls, call wait times and number of calls to resolve complaints;
- **efficiency**—weather-adjusted decline in energy usage due to efficiency adoption and peak load management and optimization;
- **clean energy mix**—increase in renewables and DERs and decline in carbon footprint relative to RPS standard transitional goals; and
- **investment**—capital and total spending below a predetermined rate, subject to carve-out for critical infrastructure investments.

To be effective in driving change, incentives and penalties must be transparent (i.e., easy to understand, calculate and report on in a timely manner). To drive and align behavior change, significant opportunity and dollars should be at risk for achieving on incentive performance, for example up to 10 to 20 percent of profits. A utility realizing a 10 percent ROE would be able to earn up to 12 percent for meeting its incentive targets. While there is no science behind that incentive number, it must be meaningful to encourage changes in behavior, and less than 10 percent is unlikely to achieve that goal. In order to encourage the behavior and innovative spirit that are essential to achieving continuous performance improvement, incentives must be durable. They must be available and achievable on an ongoing basis and subject to revisions as market conditions evolve. For capital markets to differentiate between those states that provide incentives and those that do not, durability will be an important component.

The benefit of a multiyear regulatory plan is that utilities can align their strategy with the implementation of their integrated distribution plan, which will free up resources that can be deployed in effective future planning because fewer resources will be required to process rate cases. Transparent accountability metrics and resulting incentives and penalties will provide ongoing oversight of utility performance and progress in reforming our energy future. Policymakers, through their regulatory oversight, can ensure that the integrated system plan responds to their stated objectives. In particular, agreement can be solidified on deploying and valuing renewables, such as community solar and rooftop solar. A robust integrated system plan would provide utilities with an effective roadmap for operating over the planning period with improved clarity as to the path of utility rates over that period. Each new integrated planning cycle would provide an opportunity to refine the next plan, so as to continuously improve the process and respond to customer and marketplace dynamics.

Engaging Utilities to Adopt a 21st Century Electric Utility Model

The pathway proposed in this paper looks to the utility as the facilitator, integrator and nonexclusive distribution channel to offer new products and services to its market. The utility would **not** be responsible for developing new technology, but for assessing and working with technology providers to bring best-in-class technologies to the customer base. With the support of policymakers, utilities may be allowed to own and operate (either through the regulated

The utility would not be responsible for developing new technology, but for assessing and working with technology providers to bring best-in-class technologies to the customer base.

entity or an unregulated affiliate) assets behind the meter, or at a minimum, could leverage competitive providers to offer the best price to customers. The advantage of utility ownership is scale and cost of capital benefits.

The following summarizes why utilities should be at the forefront of leading, integrating and accelerating the transition to a 21st Century Electric Utility, from the perspective of key stakeholder interests.

Benefits to Customers

- high level of recognized trust in utility providers versus a large group of unknown vendors of competitive energy services and technologies (including efficiency, demand response, load management and DER providers);
- access to customer and electric system information that supports a program for system optimization regarding future investment (subject to strong standards to protect consumer privacy);
- increased quality control oversight of third-party competitive energy service providers and products, given their scale, system knowledge, resources and lack of incentive to promote one new technology over another;
- enhanced information analytics based on customer usage experience to support customer decision making regarding innovative energy-optimization product alternatives; and
- lowest systemwide cost of deploying optimal located investments with scale technologies.

Benefits to Policymakers

- acceleration of defined policy objectives (efficiency, system optimization, environmental) through properly structured incentives and accountability for realizing results;
- ability to enhance accountability via regulatory oversight of utilities; and
- opportunity to mitigate the level of utility rate increases required by allowing utilities to earn additional revenues related to facilitating, integrating or owning new services, including behind-the-meter assets.

Benefits to Competitive Marketplace Service Providers

- endorsement of best-in-class providers and technologies;
- partnering with utilities can facilitate increased adoption of new value-add technologies; and
- partnering with utilities can reduce customer acquisition costs and thus enhance profitability (through reduced cost and increased volumes).

Benefits to Utilities

- enhanced customer service by increasing interactions with customers;
- optimized investment and reduce costs and risks;
- enhanced regional economic growth through enhanced optimization of utility system and services;
- enhanced citizenship profile;
- potential to earn incentives for achieving accountability goals; and
- ability to earn additional revenues from participating in facilitating and integrating realization of a 21st Century Utility, thereby creating potential to offset rate-increase needs and earn incremental returns for investors.

Those opposed to utilities owning behind-the-meter assets within the regulated business fear that it could: (i) complicate the regulatory model and ratemaking, (ii) increase potential financial risk to customers for un-creditworthy decisions and (iii) freeze out competitive industry players. Policymakers/ stakeholders would have to evaluate these issues when considering whether and how to allow utilities or utility-affiliated entities to participate in behind-the-meter infrastructure.

We now have an array of competitive entities seeking to offer new electricity products and services to both residential and large commercial and industrial customers. This is a positive development, but there is little, if any, oversight of the quality of the services offered, including the economic efficiency of these new inputs to the energy delivery system. Third-party entities partnering with utilities should create the right type of checks and balances by which utilities can oversee the development of new technologies that impact their system, invest as appropriate to support the grid needs and enable best-in-class technologies, and act as a distribution channel to assist in deploying new technologies. However, competitive service providers may seek utility system data to support their initiatives, and policymakers will need to resolve issues regarding data control, sharing and privacy protection.

Regulators in this paradigm would be able to drive utility accountability through appropriate and transparent customer and policy performance standards, consistent with the objectives of economic provision of reliable, clean and affordable energy services. In addition, regulators would determine how utilities would be compensated for their role in facilitating change and customer adoption through incentives, as well as penalties when performance standards are not met. They could further offer commissions for utilities facilitating sales of new products offered by vendors, and structure compensation and returns allowed on utility (or utility affiliate) ownership to allow for behind-the-meter assets.

Utilities have been timid in claiming a role in accelerating and executing a 21st Century Utility model. Several factors have likely caused a less than aggressive posture: skepticism on the part of regulators, who often suspect that utilities may earn outsized profits from future activities and, thus, have sought to encourage the competitive marketplace **without** providing rules for how utilities can participate; a strong lobbying effort by competitive market providers to prevent utilities from participating in new services; and utility compensation programs aligned with fiduciary duties that do not encourage development of new markets but focus on reliability and near-term financial performance.

Vertically Integrated vs. Restructured Utilities

Given the restructuring of U.S. electric utility markets and utilities' roles in 17 jurisdictions during the 1990–2005 period, the industry is no longer a homogeneous group of vertically integrated (distribution, transmission and generation) utilities. In most restructured markets, distribution utilities own no meaningful level of power generation and thus are less exposed to threats to the economics (and value) of the power markets. The volatility and profitability of power generation in restructured markets is borne by competitive generation companies (whether independent from utility ownership or in unregulated utility-affiliate entities). However, to the extent utilities in restructured markets collect tariffs based on energy usage, these transmission and distribution utilities remain exposed to fluctuations in customer energy usage. Thus, not all utilities will be impacted by the same set of factors in the transition to a 21st Century Utility sector.

Because vertically integrated utilities own power generation, they are more exposed than transmission ad distribution utilities to the electricity consumption impacts of DERs and various forms of energy efficiency. Declining consumption for these companies results in lower revenues to recover generation investment and the related adverse impact on market power prices (due to lower demand and increasing supply from DERs). Thus, all other factors aside, it is likely that electric generation owners, including vertically integrated utilities and competitive generators, will be less interested in moving toward a 21st Century Utility until the level of unrecovered investment in power-generation assets becomes less meaningful. This does not suggest that a transition may not occur prior to recovering greater levels of generation investment, since regulators can approve structures, such as transition charges, to accelerate change if they deem it appropriate. In fact, the e21 Initiative was developed for adoption in Minnesota, which is a vertically integrated utility market.

Utilities in restructured states have less at risk in moving forward with a 21st Century Utility sector. While these utilities may still be exposed to kWh consumption-based tariffs, the impact can be more easily managed by decoupling or other mechanisms to mitigate any drag on return on invested capital. Importantly, the highest-cost markets that are seeing the most interest in efficiency and new technologies tend to be in restructured regions. Thus, we expect that these markets will tend to be at the forefront of driving industry change.

Importantly, the highest-cost markets that are seeing the most interest in efficiency and new technologies tend to be in restructured regions. Thus, we expect that these markets will tend to be at the forefront of driving industry change.

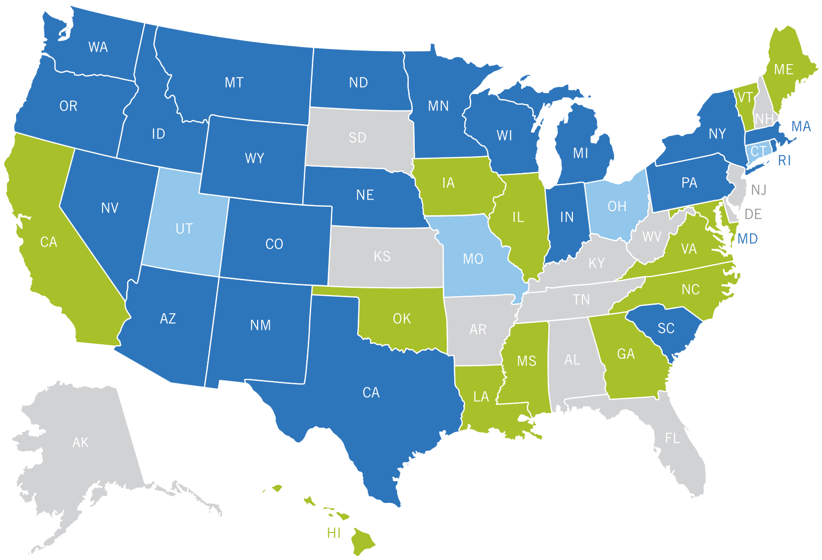
Ratemaking and Tariff Design

Important components of the evolution to a 21st Century Utility industry model are the topics of ratemaking and tariff design. For purposes of this paper, ratemaking is defined as the process by which regulators determine the appropriate aggregate annual revenue collection (or revenue requirement) utilities may recover from customers to cover costs and earn a fair return on invested capital. Tariff design refers to the structure of customer rates (or prices charged) to recover the revenue requirement allowed.

Ratemaking, which is grounded in legal precedent as to the utilities' right to recover prudent costs, is not a hotly contested issue in the 21st Century Utility debate. The ratemaking discussion has often focused on structuring a system whereby utilities have no incentive for (or are indifferent to) increased capital investment (aka rate base) to provide service, such as in the UK's RIIO model.

Tariff design is the tool that regulators use to promote policy objectives, such as equitable distribution of cost, customer usage and consumption behavior. "Disruptive Challenges" highlighted the confluence of factors challenging the long-term financial viability of our traditional utility regulatory model. The strategies proposed to address and mitigate the disruptive forces outlined were primarily regulatory solutions. Looking through an investor's lens, several tariff-restructuring alternatives were proposed. Those alternatives, which could be implemented individually or in combination, included increasing monthly fixed charges on all customers, monthly service charges for all distributed energy resource (DER) customers and/or

Figure 10: Mandatory Fee Proposals Timing Map



- Current fixed charge proposal/fight (21 states)
- New proposal expected within 12 or 24 months (4 states)
- Proposal expected (uncertain timing), or possible due to recent activity (*e.g.*, NEM debate) that could spur a proposal (13 states)
- No current or near-term expected activity (12 states)

Source: NRDC, NCLC and Vote Solar.

revising the net metering buy-back rate to be based on the wholesale value of the energy provided by the DER customer to the utility (versus the retail rate, as reflected in the majority of net energy metering programs).

Marketplace dynamics since the release of "Disruptive Challenges" suggest that two important factors were missing from that 2013 assessment: (i) the customer and policymaker view that it is not in the best interest of customers or society overall to slow the pace of technology innovation or adoption (a likely result of increased customer fixed charges), and that over the long term, technology advancement cannot be deterred by regulatory rulemaking; and (ii) customer and policymaker actions through 2015 that have demonstrated a clear policy opposition to meaningful increases in fixed charges, as evidenced by low fixed charges in place throughout the investor-owned utility industry, as well as recent actions in several states that approved nonmaterial fixed charge tariffs (e.g., Arizona Corporation Commission adopting a $5/month charge, not the $50/month charge proposed by Arizona Public Service).

Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit.

While the cost structure of distribution and transmission of electric utilities is predominantly of a fixed nature (i.e., not meaningfully impacted by volume variability or short-term business issues), utility rate structures have typically authorized a small fixed charge component. Increasing mandatory fixed charges (or demand charges), a solution proposed in *"Disruptive Challenges,"* is a tariff design tool that utilities have actively pursued since 2013 to mitigate revenue risk from disruptive forces. According to the Environmental Law and Policy Center, **24 utilities have recently proposed increases to their fixed fees**.[21] However, significant increases have met with strong opposition from customer interests and policymakers.

Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit. Fixed charges:

- do not promote efficiency of energy resource demand and capital investment;
- reduce customer control over energy costs;
- have a negative impact on low- or fixed-income customers; and
- impact all customers when select customers adopt DERs and potentially exit the system altogether, if high fixed charges are approved and the utility's cost of service increases.

While DER customer charges can be structured to reflect

21 Environmental Law and Policy Center Foundation, June 2015.

the value of the grid connection that is maintained by practically all DER customers, such charges will need to consider whether and at what level a DER buy-back rate (the price paid for energy by a utility to a DER supply customer) should be set. Through a win4 lens, it is clear from recent regulatory actions reconfirming support for DERs and net energy metering that policymakers are interested in DER development and customers want the option to choose their own energy supply.

It is therefore in the long-term best interests of utilities to support such choice, consistent with regulatory policies that support financial viability and avoid meaningful monthly fixed charges. By instituting monthly DER customer grid fees or reducing buy-back rates, it is likely that rooftop solar activity will be slowed, and this must be considered in the policy debate. This is consistent with the early experience of the Salt River Project (SRP), which is not regulated by the Arizona Corporation Commission and implemented a $50/month renewable customer grid charge for all new rooftop installations. Since that announcement, one major rooftop supplier reported a 96 percent decline in new solar applications in the SRP territory.

Besides the installed cost advantage of utility-scale solar versus rooftop solar and system optimization considerations, community or utility-scale solar brings the advantage of renewables to all customers without the potential cross-subsidy issues associated with rooftop solar.

Given the new tools available to enhance system wide efficiency, including peak load management, time-of-use rates can be an important tool in managing a dynamic optimization of resources as market demand and supply evolve in a technology-enhanced 21st Century Utility model.

Tariff Design Principles for a 21st Century Electric Utility

As we consider fairness to all customers, we should provide incentives to fund the most cost effective renewable options. In October 2015, the Hawaii PUC halted its net energy metering program for new systems due to penetration in excess of 20 percent. This is the first significant action to slow the growth of rooftop solar penetration due to the high cost that NEM programs shift to non-DER customers. In a recent study prepared by the Brattle Group entitled, “Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado’s Service Area,” the findings demonstrate that “utility-scale PV system is significantly more cost-effective than residential-scale PV systems when considered as a vehicle for achieving the economic and policy benefits commonly associated with PV solar. If, as the study shows, there are meaningful cost differentials between residential and utility-scale systems, it is important to recognize these differences, particularly if utilities and their regulators are looking to maximize the benefits of procuring solar capacity at the lowest overall system costs.”[22]

Given the significant net cost benefit of approximately 45 percent for utility-scale solar (due to capacity costs and power output optimization), pricing of rooftop solar and related subsidies, and other energy technology alternatives, should be determined by the most efficient alternative opportunity, after factoring in grid-related costs and benefits. Tariff fairness can be structured, such as by adopting renewable grid charges or adjusting DER buy-back rates (i.e., net metering), in a way that factors in the economic value of adding renewables to the grid and creates an opportunity for all customers to benefit equally from the adoption of renewables, not just homeowners who can deploy solar on their rooftops.

Without increased demand for electricity sales, fixed charges to all customers, or DER grid charges, utilities will continue to be exposed to customer switching and under recovery of revenues. This is especially true for utilities with inclining block tariffs (i.e., the more you use, the higher the rate for incremental energy consumed) that are in excess of the cost of DER alternatives. The result of ongoing customer adoption of DERs in net energy metering states (43 of 50) is that future rate increases are required to offset the revenue lost from those customers adopting DERs. This scenario feeds a cycle of customer adoption of DERs and eventually results in increasing rates for non-DER customers. The advent of (i) bidirectional metering, (ii) most economical value of renewable buy-back rates and (iii) revenue-decoupling mechanisms can assist in mitigating this risk.

Time-of-use (or real-time) pricing has the potential to be an important tool in optimizing system capacity and moderating incremental capital investment in electric energy infrastructure. While this type of tariff design has been discussed for years and is supported by smart-meter technology investment, policymakers have generally not supported it. The lack of support from policymakers is a roadblock to moving forward on a 21st Century Utility model.

Time-of-use rates have not been widely implemented due to technical constraints—a lack of smart-meter

22 The Brattle Group, “Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado’s Service Area,” Prepared for First Solar, July 2015.

infrastructure—and a lack of public interest. Customer concerns include lack of understanding, potential volatility of bills, and impact on low- and fixed-income customers. Given the new tools available to enhance system wide efficiency, including peak load management, time-of-use rates can be an important tool in managing a dynamic optimization of resources as market demand and supply evolve in a technology-enhanced 21st Century Utility model. Thus, we need to expand our efforts to educate and pilot these programs. While "opt-in" programs have often realized low adoption levels, another alternative to consider is selected "opt-out" programs, where appropriate, to encourage realization of policy objectives.

Factoring in financial viability considerations and customer and policy preferences, the following tariff principles are components of a tariff design that can contribute to the development of a 21st Century Utility model:

- introducing inclining block rates to promote efficiency of energy consumption;
- decoupling of revenues from volumetric usage charges to protect cost-recovery shortfalls in the short-term, for example due to customers switching to DERs or declining usage due to new technologies; however, decoupling does not reduce the long-term vicious cycle of increasing customer adoption of DERs created by increasing rates;
- providing bidirectional meters to all DER customers so that energy consumed from utilities would be charged based on utility tariff schedules, and buy-back rates for DER-produced energy at a value of renewable rates;
- setting the value of renewable rates at the higher of competitive wholesale energy prices or the levelized cost of the lowest incremental cost to deploy efficient renewables (e.g., lower of rooftop vs. utility scale, with adjustments based on evaluation of system costs and benefits); and
- establishing time-of-use rates to optimize system efficiency; time-of-use rates will enhance the value of new technology investment as customers optimize the value of this rate structure (e.g., using appliances with time-of-use controls).

With these principles in place, tariff economists can fine-tune potential tariff structures to support a 21st Century Utility model. Each jurisdiction will have its own unique issues and cost structures that will impact the ideal approach in its market. Since we are likely to grandfather existing DER customers during the transition period, we should address the tariff issue now to define the ultimate transition period, provide fairness to all customers and mitigate financial risk to customers and utility investors.

Financial Issues

The financial health of utilities has improved over the last several years, based on the support of regulators for allowing recovery of revenue shortfalls due to declining consumption and customer growth, with increased use of decoupling of revenues from consumption in some form now in over 28 jurisdictions. In addition, a decline in the cost of fuel to generate power, lower merchant power prices and lower interest rates have provided additional headroom for base utility rate increases. In this environment, and reflecting lower interest rates in the financial markets, utility credit ratings have stabilized from the continuous decline experienced from the 1960s through 2010, and utility equity prices have been at or near all-time highs on a dollar price and multiples-of-earnings basis. Investors are generally pleased with the utility sector's performance, and likely hope the current business model prevails for the foreseeable future. Unfortunately, hope is not a strategy.

However, below the surface, lie foundational shifts that suggest the steady period of utility performance will be challenged by customer choice, the adoption of new customer-driven technologies and customer behavior changes driven by social and economic forces

However, below the surface, as described in countless industry trade articles and in "Disruptive Challenges," lie foundational shifts that suggest the steady period of utility performance will be challenged by customer choice, the adoption of new customer-driven technologies (e.g., Nest) and customer behavior changes driven by social and economic forces (e.g., smaller homes). Investors have shown from prior experiences in other industries that they become noticeably concerned about disruptive challenges when the loss of sales and revenues is reflected in financial results. For utilities, this can happen when serious rate-increase opposition accelerates due to the impact of increasing penetration of DER technologies.

Although these disruptive challenges are well outlined in utilities' SEC filings, utility managements are managing their businesses based on the current framework and their fiduciary duty to focus on quality service for customers and growth in near-term earnings and investment value for investors. As long as investment spending supports growth through increased rate needs, the problems lurking in the future are kicked down the road, although one could argue that the problems are amplified by increasing utility rates in the short term. In addition, utility management compensation is focused on near-term reliability and financial goals, creating a fiduciary obligation and compensation incentive for management to focus on the near term.

For the time being, all may appear well, but if one believes that risks are at play, when these threats become a financially reality, investment values will be impacted. Capital availability will decline as investors focus on the potential for declining profitability and the risk of stranded assets or cost levels that the remaining customer base may be unwilling to bear. Given the importance of utility access to capital to support the grid, this is not an acceptable scenario.

The objective is not to create fear or call for a death spiral, but to commence the transition now to a future that customers support and in which utilities can play a constructive role and access the capital required to build this future. As a point of reference, who would have thought that essential service industries in a growing economy such as the airlines and the landline phone business would not support investment-grade quality ratings as stand-alone entities?

The New 21st Century Electric Utility

The current transition of the electric utility framework into a new model is being led by economic and technological forces that will ultimately drive change. This is particularly true given the support of policymakers for customer choice of electric supply and new technologies to drive efficiency, system optimization and the reduction of our environmental footprint through expanding our mix of clean energy sources.

The actions by states to date in considering meaningful regulatory change have been predominantly in support of a free marketplace for competitive providers to offer their new services to customers directly or through utility-run efficiency programs. In that environment, the utility is relegated to grid provider, and policymakers have few levers to oversee or influence the marketplace to achieve their vision.

The environment that this paper proposes is one in which the utility is responsible for the development and operation of the grid, but is also encouraged and accountable for accelerating our progress toward a 21st Century Utility model. The utility will be encouraged and accountable for promoting the adoption of new technologies, and for developing a cost-effective plan to deploy technology in the most efficient way to control customer costs. In this scenario, cost of capital on new investments might consider returns on selected operational spending (similar to the UK Totex model) that mitigates less-than-optimal capital investment. Utilities would also play a traffic cop role by allowing only proven technologies or vendors entry to their application store.

Utility revenues will be determined by regulators to encourage a return on invested capital, particularly for the legacy system in place, and transparent incentives to encourage accountability for accelerating change and policy realization. It may be a challenge to develop tariff mechanisms and incentives, since there exists a distrust of providing utilities an opportunity to increase their returns above currently allowed levels. But common sense and economic theory demonstrate that the best way to achieve results is to provide economic incentives. Regulators will continue to regulate, and thus any midcourse correction deemed necessary can be implemented. The objective is to develop a formula by which customers are served, policy is realized, technology adoption and product offerings by competitive entities is accelerated, and utilities are motivated to achieve the objectives of customers and policy while maintaining financial viability to support the grid.

Concluding Comments: Transitioning to the New Utility Model

The transition to a new industry paradigm will require the proactive support of customers, policymakers and utility regulators, competitive-market service providers, and utilities. In the ideal world this would be a collaborative process, driven by policymakers who understand that the industry model needs to be refined in order to promote the full suite of opportunities that can be created by a 21st Century Utility. A mutual understanding of the benefits of collaboration and economic benefits to all parties is key to a productive process and for defining a clear transition and end state.

Figure 10: The Pathway to a 21st Century Utility Model Vision

Vision:

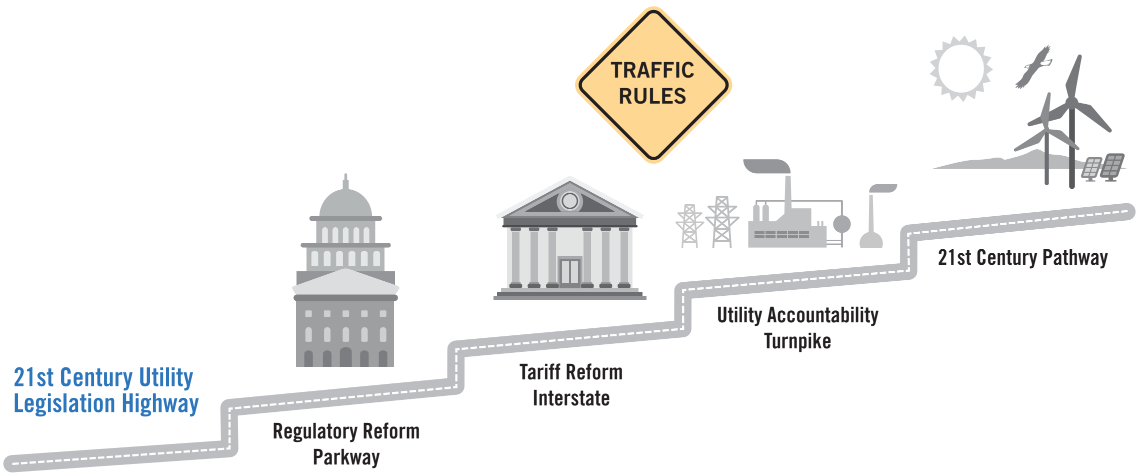
- Enhanced reliability and resilience of the electric grid while retaining affordability;
- An increase in cleaner energy to protect our environment and global strategic interests;
- Optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- A focus on customer value, including service choices and ease of adoption.

Foundational Principles:

- Financially viable utilities essential to fund and support an enhanced electric grid;
- Policymakers must promote clear policy goals as part of a comprehensive, integrated 21st Century Utility Model;
- Commitment to engaging and empowering customers to make intelligent energy choices; and
- Equitable tariff structures that promote fairness and economic and environmental policy goals.

Pathway:

- State policymakers pursue legislation to outline the model for a 21st Century Utility;
- Regulatory reform to support efficient resource deployment and accountability;
- Tariff structures refined to support price signals and financial viability requirements;
- Utilities empowered and accountable for managing the Transition.



To make progress, it is important to begin this transition soon and oversee its continual evolution. The process to accomplish this transition is not regimented, but should include the following steps:

- define the objectives, vision and foundational principles for a 21st century electricity market;
- identify the transitional constraints and roadblocks to navigate to the end-state market;
- consider the roles and interactions of key market participants, including utilities and competitive service providers;
- define utility tariff structure objectives and approaches to realizing objectives;
- identify alternative incentives and hold utilities accountable for accelerating and integrating system optimization;
- define a timeline for commencing the study process and transition to the end state;
- identify a process to revise the utility model through the transition, as appropriate; and
- define the impact of the new model on the regulatory oversight process.

The policies set forth for a 21st Century Utility model and the pathway for achieving results will create a significant opportunity for economic growth and regional competitiveness.

No two states will apply the same approach, but the goal is to develop several robust models that can be tested and compared against each other to refine into best-in-class models over time. The policies set forth for a 21st Century Utility model and the pathway for achieving results will create a significant opportunity for economic growth and regional competitiveness. Over the long term, these proactive solutions will create shared benefits for customers, utility investors and society as a whole.

Ceres

Ceres
99 Chauncy Street
Boston, MA 02111
T: 617-247-0700
F: 617-267-5400

www.ceres.org

EXHIBIT KRR-5

Utility Dive

The future of rate design: Why the utility industry may shift away from fixed charges

The animosity over fixed charges is giving way to a debate over comprehensive rate reform

By Gavin Bade | November 19, 2015

Less than three years after the utility industry first introduced fixed charges into its playbook, state regulators and utilities across the country appear to be looking for a new approach to growing concerns over load defection.

In January 2013, the Edison Electric Institute, the national trade group for investor-owned utilities, released its landmark "Disruptive Challenges (http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf) " report. The report's most notable recommendation was to advise utilities to increase fixed charges to make up for stagnant load growth and customers installing their own distributed generation.

Utilities across the nation took to the recommendation. Last November, Utility Dive reported that there were at least 23 separate fixed charge proposals (http://www.utilitydive.com/news/the-fight-over-solar-moves-from-net-metering-to-rate-design/327742/) being considered by state regulators across the country, and the trend has continued through 2015. A recent report (https://nccleantech.ncsu.edu/wp-content/uploads/50-States-of-Solar-Q3-FINAL_25.pdf) from the NC Clean Energy Technology Center found that there were 26 open dockets in 18 states relating to fixed charge increases in the third quarter of this year.

But as quickly as fixed charges came into vogue, they now appear to be on the way out.

After two years of contentious battles (http://www.utilitydive.com/news/the-fight-over-solar-moves-from-net-metering-to-rate-design/327742/) between utilities and solar advocates, the blowback against the wave of fixed charge proposals has led regulators and stakeholders to seek a new approach. Recently, even the author of the original "Disruptive Challenges" paper reversed his original position on fixed charges in a recent paper for Ceres, plotting out a new approach (http://www.utilitydive.com/news/beyond-fixed-charges-disruptive-challenges-author-charts-new-utility-pat/408971/) for utility business models that doesn't include high fixed charges.

Regulators call for balanced approach at NARUC

The new approach to rate design was on display last week at the annual meeting of the National Association of Utility Regulatory Commissioners (NARUC) in Austin, Texas.

At a panel on the future of rates, Samantha Williams, attorney and energy policy advocate at the Natural Resources Defense Council (NRDC), explained that most regulators have not viewed the fixed charge trend kindly.

“Approving these proposals does appear to be the outlier,” she said. “Nearly three quarters of the decisions that have been put out so far in 2015 on this issue have either denied the fixed charge outright or commissioners have scaled it back considerably.”

EEI Executive Vice President David Owens stressed to the audience that utilities must create a rate design that will enable the transition to a networked grid where bidirectional power flows are the norm.

The utility sector is in a “significant state of transition to a 21st century distribution system,” he said. “The rate design has got to anticipate that we’re moving to a network, and the rate design has got to anticipate that we need to modernize the grid in order to achieve that.”

Because many of the regulators in the audience are currently overseeing open proceedings on rate design issues, Owens and the rest of the panelists could not discuss specific examples, and the EEI executive was careful not to openly endorse any specific rate design. But he stressed that rate design issues should be approached from the standpoint of enabling more integration of DERs onto the grid, while preventing cost shifts and keeping price impacts to a minimum.

“There’s an array of approaches for dealing with this,” he said. “You can have a grid access fee. You can have a minimum bill, which looks at whether you’re supplying your own needs or making excess for the grid. You can create a special category for distributed generation, look at standby charges, or a three-part rate.”

“I know that’s very controversial,” he added, “but there’s an array of approaches that need to be discussed that seek to achieve this outcome and acknowledge that we’re all about grid modernization.”

So what is good rate design, anyway?

David Owens' stated goal — designing rates to boost integration of distributed resources while keeping costs down — is a relatively uncontroversial one for utility sector stakeholders. The debate, as always, is about how to get there.

Jim Lazar, senior advisor at the Regulatory Assistance Project (RAP), thinks his organization has a solution. In a recent report (http://www.raponline.org/document/download/id/7842) , he and his colleagues laid out a residential rate design they think is broadly applicable throughout the nation and that can help resolve some of the lingering disputes in the sector.

Much like the recent rate design reform in California, RAP envisions a three-part residential rate: A low fixed charge, time-of-use pricing, and inclining block rates.

Time-of-use rates will encourage customers to shift their usage to non-peak hours, Lazar told the NARUC audience, while the inclining block rates — which increase the cost of electricity per kWh as usage increases — incentivize them to use electricity frugally.

The fixed charge, he said, should only apply to the customer-specific costs of connecting to the grid, while shared infrastructure costs “should be recovered through some measure of usage,” rather than fixed charges.

Lazar compared that rate design to a less desirable construction — a rate with high fixed charges and a flat volumetric rate.

That rate structure, he said, “encourages customers to use more and creates a continued need for operation of marginal resources.”

In addition to the three-part rate design, Lazar would include a residential demand charge and a critical peak pricing component “for the 10 or so times a year when the grid is really stressed.”

The difference between a good and a bad rate design can be significant for utilities. When taking into account expected increases in electricity consumption from poorly designed rates, the RAP team estimates that “the difference between good and bad rate design can mean a 15% difference in customer usage.”

“15% is a lot,” Lazar said. “It translates into about half the Clean Power Plan emission reduction [requirements] for our nation. That’s big.”

The future: Residential demand charges and more

Demand charges for residential customers are a relatively recent approach for electric utilities, and RAP’s recommendation for their inclusion sparked discussion on the NARUC panel.

Lazar stressed to the audience that his organization’s design for residential demand charges is a limited one, and the price should reflect the scale of customer usage.

"We actually have a demand charge, but only from a customer-specific capacity — the line, transformer, and secondaries to connect to the grid," he said. "The apartment will pay $2 or $3; the large mega-house will pay more like $15 or $20 to connect to the grid."

NRDC's Williams largely endorsed the RAP proposal, agreeing that the "lion's share of the customer's bill should be volumetric." However, she said the team at NRDC is still evaluating the concept of residential demand charges. Central to the considerations should be the charges' impacts on distributed generation.

Already, Arizona utilities Tucson Electric Power (http://www.utilitydive.com/news/arizona-utility-tep-wants-to-add-solar-fee-reduce-net-metering-credit/408791/) and Salt River Project (http://www.utilitydive.com/news/srp-board-votes-to-increase-charges-on-solar-owners/369377/) have proposed demand charges for rooftop solar customers in response to burgeoning distributed generation in their state, a move that solar advocates say will hurt the resource's value. However, analysts told Utility Dive earlier this year (http://www.utilitydive.com/news/whats-next-in-the-energy-storage-boom-and-what-utilities-need-to-know/382465/) that such charges could have the unintended consequence of promoting the installation of more distributed storage, since the customer-sited batteries could allow users to cut their peak usage, avoiding high charges.

Stopping short of openly endorsing a specific rate design, EEI's Owens seemed to support the rate design approach undertaken by RAP.

"A three-part rate with a demand charge gives customers ability to say, 'Let me adjust my demand to when my utility has its highest demand,'" he said.

During an exchange with Lazar, the EEI executive pointed out that the conversation was based on the assumption "that the way we traditionally designed rates is wrong, so we need to redesign rates so they tie into cost causation and all those other elements."

"I don't disagree with that," he said, "but we're not going to revolutionize ratemaking overnight. I do agree with time differentiated rates, but I also know that many are pushing back."

"All I'm trying to suggest to you," Owens said, "is with these changing techs, we need to sit down and have a serious conversation about a whole array of ratemaking approaches … There's a whole array of approaches, but let's get the conversations started. We have to roll up our sleeves and begin to have a collaboration on these issues [that are] very important to consumers."

Top Image Credit: Flickr user Sarah Elizabeth Simpson (http://www.flickr.com/photos/sarah_elizabeth_simpson/4288149788/sizes/z/in/photostream/)

Filed Under:

Generation Solar & Renewables Energy Storage Distributed Energy Efficiency & Demand Response Regulation & Policy

EXHIBIT KRR-6

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 4

CAC Request 4-005:
Attachment 2-C shows a significant number of residential customers using 100 or fewer kWh per month. a. How many of these customer accounts are occupied residential dwellings/homes that are occupied 12 months out of the year? b. How many of these customer accounts are cabins, vacation homes, or other units that maintain year-round service but are not occupied full time?
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: Attachment 2-C shows the residential customer distribution of actual usage of customers with 12 billing months of registered energy consumption above 0 kWh. The "% of Customers" at 100 kWh/month in the graph is the count of those customers that had usage each of the 12 billing months that averaged between 51 and 149 kWh per month. a) NIPSCO does not know the occupancy patterns or utilization for residential customer locations. b) See response to (a.) above.

EXHIBIT KRR-7

Customer Charge Resolution- 2015-1

NASUCA Customer Charge Resolution-2015-1

THE NATIONAL ASSOCIATION OF

STATE UTILITY CONSUMER ADVOCATES

RESOLUTION 2015-1

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE

DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

Whereas*,* gas and electric utilities' own embedded cost of service studies,[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S;[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved**,** that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers**;**

Be it further resolved, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved**,** that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015

Philadelphia, Pennsylvania

No Vote: Wyoming
Abstention: Vermont

[1]*See, e.g.,* Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates,* PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company,* AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]*See* Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natur4al Gas Rates,* Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

[5]*Id.* at 7-8.

[6]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7]*See* ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates,* AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

June 10th, 2015 | Consumer Protection

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

8380 Colesville Road, Suite 101
Silver Spring, MD 20910
Phone: (301) 589-6313
Fax: (301) 589-6380
e-mail: nasuca@nasuca.org

EXHIBIT KRR-8

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 4

CAC Request 4-006:
What is the average household income of a low-income household in NIPSCO's service territory?
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Please see Objection. NIPSCO does not have the information requested.

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 4

<u>CAC Request 4-007:</u>
Please provide any and all analysis and data conducted by or for the Company relating to household energy burden—electricity bills as a percentage of household income—for low and moderate income customers, segmented according to customers at or below the Federal Poverty Level in income, and customers at or below twice the Federal Poverty Level in income.
<u>Objections:</u>
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
<u>Response:</u>
Please see Objection. NIPSCO does not have any such analysis or data.

EXHIBIT KRR-9

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 6

CAC Request 6-007:
Do you have any projections on the effects of the increase in fixed customer charges on customer willingness to invest in energy efficiency or distributed generation? Please provide any analysis you have conducted and any e-mails related to this issue.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: Please see objection. NIPSCO has not conducted any such studies.

EXHIBIT KRR-10

	A	B	C	D	E	F	G	H
1	**CAC Request 6-001 a.**							
2	Line	(kW)		2010	2011	2012	2013	2014
3	1	Total Distributed Capacity[A]		802,207	805,424	818,942	826,986	827,378
4	2	Nipsco Generation Capacity[B]		3,422,000	3,422,000	3,422,000	3,405,000	3,405,000
5	3	Total System Capacity (Lines 1 + 2)		4,224,207	4,227,424	4,240,942	4,231,986	4,232,378
6	4	% of Total System Capacity (Line 1 / 3)		19.0%	19.1%	19.3%	19.5%	19.5%
7								
8	Footnotes:							
9	A. Based upon Net Metering, Feed In, and Large Industrial customers.							
10	B. Total Nipsco System Capacity is based on historical Integrated Resource Plan filed with the IURC.							
11								
12								
13	**CAC Request 6-001 b.**							
14	Total Number of Customers[1] with Distributed Generation by Rate							
15			Customer Class	2010	2011	2012	2013	2014
16			611	34	46	46	53	67
17			621	0	3	7	9	13
18			623	0	0	2	3	3
19			632	4	4	4	4	4
20			633	2	2	2	2	2
21			665	0	1	55	95	95
22			Not Applicable[2]	4	5	7	7	7
23			Total	44	61	123	173	191
24								
25	Footnotes:							
26	1. Customer count based upon Net Metering and Interconnection IURC Reports and Large Industrials							
27	2. Not Applicable customers do not particpate in the Feed In or Net Metering programs.							

EXHIBIT KRR-11

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 6

CAC Request 6-001:

For 2010 through 2015, please provide the following information for each year:

a. The amount of distributed generation capacity as a percent of total system capacity

b. The number of customers with distributed generation, for each customer class

c. The amount of energy produced by customers with distributed generation as a percent of total system energy

d. The amount of energy produced by customers with distributed generation as a percent of total consumption for each customer class

e. Average monthly electricity consumption of customers with distributed generation, for each customer class

f. Average monthly electricity consumption of customers as a whole, for each customer class

g. The total number and percentage of NIPSCO's distributed generation customers that consume less electricity than the class average, for each customer class.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is vague and ambiguous in that "Distributed Generation" is undefined. For purposes of this request, NIPSCO interprets distributed generation to include all behind the meter generation of which NIPSCO is aware.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is vague and ambiguous in that "Customer Class" is undefined. For purposes of this request, NIPSCO is interpreting customer class to mean the Rate Class to which the customer belongs.

NIPSCO further objects to subparts (a) and (b) of this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret information.

NIPSCO further objects to subpart (c) of this Request on the separate and independent grounds and to the extent that this Request seeks publicly available information.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

a) Please see the file attached hereto as CAC Set 6-001 Confidential Attachment A, which is a list of large industrial customers with internal generation and CAC Set 6-001 Attachment B, which contains a table of the distributed generation capacity as well as its percent of total system capacity. NIPSCO will provide 2015 data when it becomes available.
b) Please see subpart a.
c) Please see objections. Those customers with Feed In Tariffs is contained in the Feed in tariff report, which is publicly available.
d) Please see objections.
e) Please see objections.
f) Please see objections.
g) Please see objections.

EXHIBIT KRR-12

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 6

CAC Request 6-002:
Please provide NIPSCO's projected growth of distributed generation capacity, energy production, and overall number of distributed generation systems in its service territory for each of the following years: 2016, 2017, 2018, 2019, 2020.
Objections:
Response:
Based on NIPSCO's 2014 IRP, in 2015 through 2018, an incremental 66 MW of distributed generation capacity was anticipated; 16 MW from Feed-In Tariff Phase II and 50 MW of future distributed generation designed to be as close to market neutral as possible. The energy production was forecast only for the 50 MW as 86.5 GWH, 90.2 GWH and 89.9 in years 2018, 2019 and 2020 respectively. The 16 MW for the Feed-In Tariff had not yet been approved and the technology applications were unknown. The number of systems was not estimated.

EXHIBIT KRR-13

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 6

CAC Request 6-003:
Please provide NIPSCO's projected claimed revenue loss due to distributed generation in its service territory for each of the following years: 2016, 2017, 2018, 2019, 2020. Please provide all calculations and assumptions to support these projections.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO has not performed and supplied any such analysis in this proceeding. Please see NIPSCO's response to CAC Request 6-004.

EXHIBIT KRR-14

Cause No. 44688
Northern Indiana Public Service Company's
Objections and Supplemental Responses to
Citizens Action Coalition's Data Request Set No. 6

CAC Request 6-004:
Please provide NIPSCO's claimed revenue loss due to distributed generation in its service territory for the historical test year used in this case. Please provide all calculations and assumptions to support this projection.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: The effects of distributed generation, included impact on actual revenue, are reflected in the actual usage of customers provided in the historical test year in this case. Please see the response to CAC Request 6-001 for a compilation of distributed generation interconnected to NIPSCO's system. As evidenced by the interconnections, NIPSCO has been a proponent of distributed generation through cooperation with customers with behind-the-fence applications, a Renewable Feed-in Tariff and the Net Metering Rider.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO, TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	**)**	**CAUSE NO. 44688**

DIRECT TESTIMONY OF JOHN HOWAT ON BEHALF OF

CITIZENS ACTION COALITION AND
THE ENVIRONMENTAL LAW & POLICY CENTER

January 22, 2016

I. INTRODUCTION

Q. Please state your name, job title, employer and business address.

A. My name is John Howat. I am a Senior Policy Analyst at the National Consumer Law Center ("NCLC"), 7 Winthrop Square, Boston, MA 02110.

Q. **Please describe your professional background and experience.**

A. At NCLC over the past fifteen years, I have managed a range of regulatory, legislative and advocacy projects across the country in support of low-income consumers' access to utility and energy related services. I have been involved with the design and implementation of energy affordability and efficiency programs, regulatory consumer protections, rate design, issues related to metering and billing, credit scoring and reporting, and energy burden and demographic analysis. I have worked on behalf of community-based organizations or their associations in Arkansas, Arizona, California, Idaho, Illinois, Indiana, Kansas, Louisiana, Massachusetts, Mississippi, Nevada, New Jersey, New Mexico, Pennsylvania, Rhode Island, Texas, Utah, Vermont, Washington and Wisconsin. I have worked under contract on low-income energy and utility issues with the U.S. Department of Health and Human Services, Oak Ridge National Laboratory, the National Energy Assistance Directors' Association, and the Office of the Attorney General in Nevada, the Ohio Consumers' Counsel, and AARP. I have presented testimony or comments before utility regulatory commissions in California, Idaho, Illinois, Indiana, Louisiana, Massachusetts, Missouri, New Mexico, Nevada, New Jersey, Pennsylvania, Rhode Island, Texas, Vermont, and Washington State. In addition, I am a presenter at conferences of National Community Action Foundation, National Low Income Energy Consortium, National Energy Assistance Directors' Association, National Association of Regulatory Utility Commissions and National Association of State Utility Consumer Advocates. I am co-author of Access to Utility Service, a law and policy manual published by National Consumer Law Center; and primary author of "Home Energy Costs: The New Threat to Independent Living for the Nation's Low-Income Elderly," published in Clearinghouse Review, Vol. 9 - 10, Jan - Feb 2008; "Tracking the Home Energy Needs of Low-Income Households through Trend Data on Arrearages and Disconnections," National Energy Assistance Directors' Association, 2004, http://www.neada.org/publications/Tracking_the_Need.pdf; and "Public Service Commission Consumer Protection Rules and Regulations: A Resource Guide," National Energy Assistance Directors' Association, 2006, http://www.neada.org/publications/Consumer_Protection_Guide.pdf.

I have been professionally involved with energy program and policy issues since 1981. Prior to joining the Advocacy Staff at National Consumer Law Center, I consulted with a broad range of public and private entities on issues related to utility industry restructuring. Previously, I worked as Research Director of the Massachusetts Joint Legislative Committee on Energy, responsible for the development of new energy efficiency programs and low-income energy assistance budgetary matters; economist with the Electric Power Division of the Massachusetts Department of Public Utilities, responsible for analysis of electric industry restructuring proposals; and Director of the Association of Massachusetts Local Energy Officials. I have a Master's Degree from Tufts University's Graduate Department of Urban and Environmental Policy and a Bachelor of Arts Degree from The Evergreen State College.

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

A. Yes. I testified before the Commission in Cause No. 43669 regarding the gas utility energy assistance programs of Citizens Gas, Northern Indiana Public Service Company, and Vectren Energy Delivery. I also testified before the Commission in Consolidated Cause Nos. 44576 and 44602 regarding issues related to the affordability and equity of Indianapolis Power & Light Company's proposed rates and rate design.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Citizens Actions Coalition of Indiana, Inc. ("CAC") and the Environmental Law & Policy Center ("ELPC") (collectively, "Joint Intervenors").

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to address issues related to the affordability and equity of Northern Indiana Public Service Company's ("NIPSCO" or the "Company") proposed rates and rate design. Testimony that follows will:

- Describe the need for and recommend that the Commission direct NIPSCO to implement a comprehensive low-income bill payment assistance program that targets current bill benefits to NIPSCO customers eligible to participate in the federal Low-income Home Energy Assistance Program ("LIHEAP") and includes an arrearage management design component;
- Recommend that NIPSCO report monthly to the Commission and stake-holders data regarding general residential and low-income customer accounts, billing, receipts, arrearages, notices of disconnections, bill payment agreements, disconnections of service for nonpayment, reconnections of service after disconnection for non-payment, accounts written off as uncollectible, and accounts sent to collection agencies. I will present data reporting models from Ohio, Illinois, Pennsylvania and Iowa.
- Present evidence demonstrating that increasing utility cost recovery from the volumetric to the monthly customer charge portion of bills disproportionately harms low volume consumers within a rate class. I will show that on average low-income households, households headed by an

African American person, and households headed by a person over the age of 65 use less electricity than their counterparts, and that increased monthly fixed or customer charges therefore unfairly and unjustly cause disproportionate harm and exacerbate pre-existing electric utility affordability and home energy security problems faced by many of these households. Accordingly, I will recommend that the Commission reject NIPSCO's proposal to increase the monthly fixed customer charge.

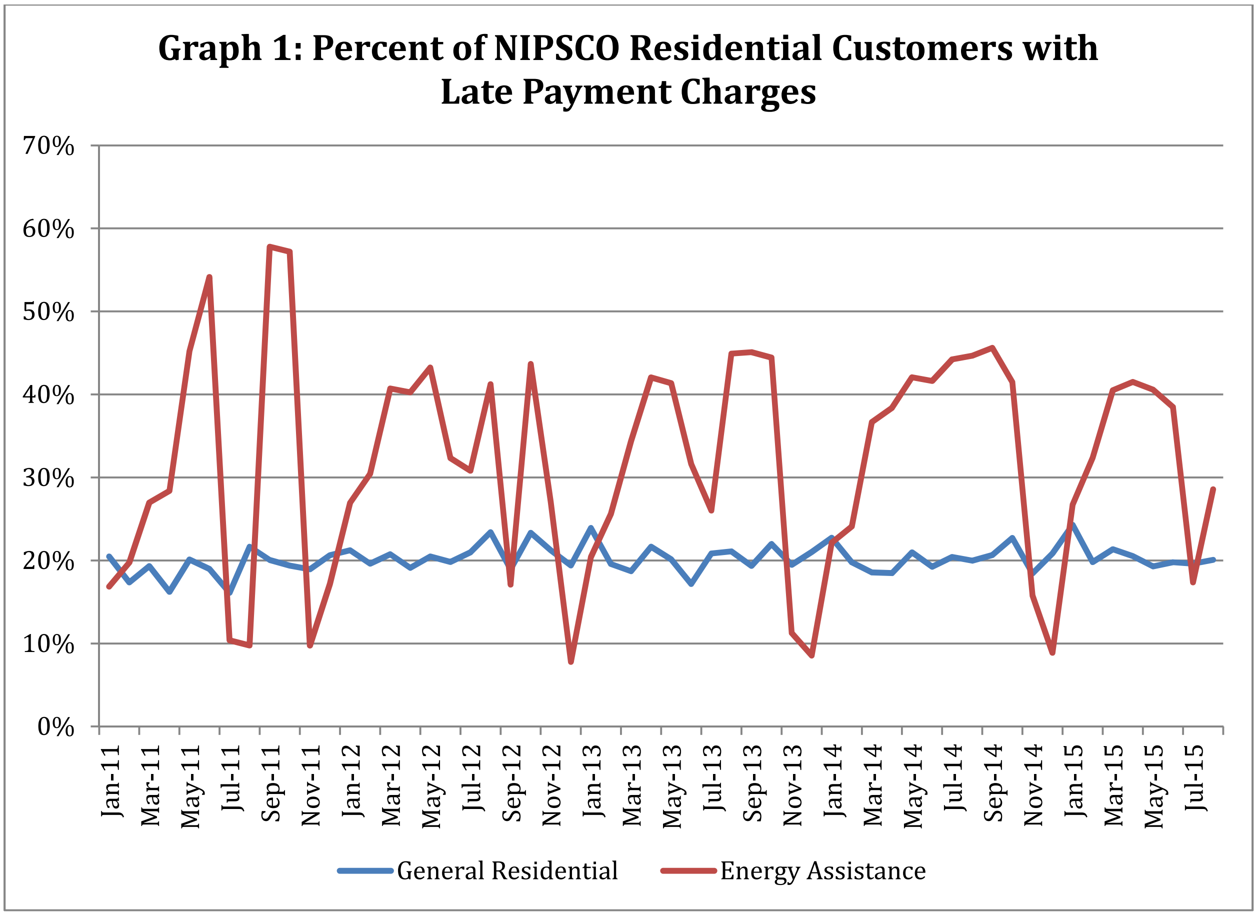
II. LOW-INCOME BILL AFFORDABILITY AND PAYMENT DIFFICULTIES IN THE NIPSCO SERVICE TERRITORY

Q. Is there an electricity service affordability problem among NIPSCO's lower-income residential customers?

A. Yes. Observing recent trends in late payment fees and notices of disconnection for nonpayment among NIPSCO's low-income residential customers receiving benefits through LIHEAP and NIPSCO's general residential customers not participating in LIHEAP reveals burdensome payment difficulties among many low-income customers.[1] During the period of January 2011 and August 2015, a monthly average of 32% of NIPSCO's residential electric service customers

[1] Indiana caps participation in LIHEAP to households living at or below 150% of the federal poverty guidelines. However, because of the lack of detailed household income data applicable specifically to the NIPSCO service area, NIPSCO customers participating in LIHEAP may serve as a proxy for "low-income" for purposes of analyzing payment difficulties.

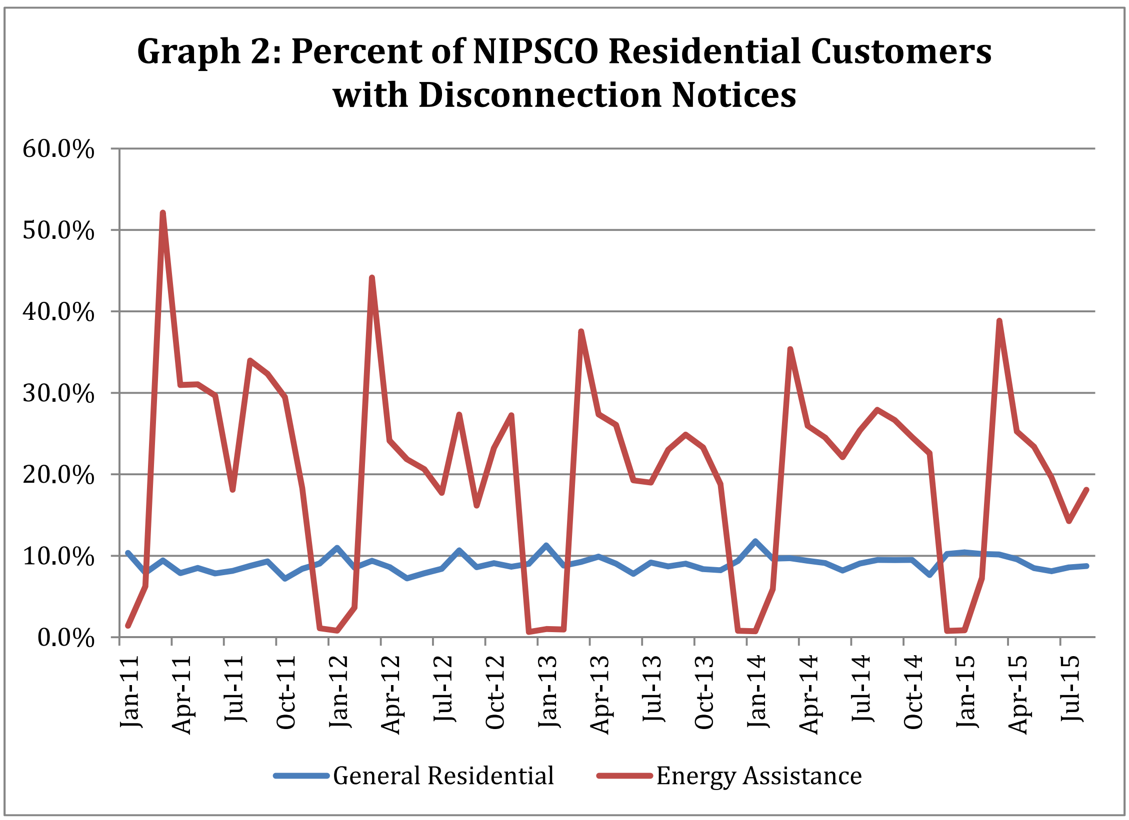
enrolled in LIHEAP paid a late payment fee.[2] As reflected in Graph 1, below, 40% or more of NIPSCO's LIHEAP customers paid a late payment fee during over one third of the months reported. In addition, a monthly average of 20% of NIPSCO's general residential customers not enrolled in LIHEAP paid late payment fee.[3]



[2] NIPSCO Response to CAC Set 1-6 Supplemental Attachment A, Tab A (<u>Exhibit JH-1</u>) and Tab V (<u>Exhibit JH-2</u>).

[3] NIPSCO Response to CAC Set 1-5 Attachment A, Tab A (<u>Exhibit JH-3</u>) and Tab V (<u>Exhibit JH-4</u>).

Notices of disconnection for nonpayment represent another indicator of utility bill payment trouble and that customers are experiencing affordability problems. As illustrated below in Graph 2, the disconnection notice rate among NIPSCO's low-income residential electric service customers participating in LIHEAP averaged 20% and peaked between 35% and 52% in March, as the winter disconnection moratorium expires.[4] The monthly average disconnection notice rate among residential customers not enrolled in LIHEAP was about 9%.[5]



---

[4] NIPSCO Response to CAC Set 1-6 Supplemental Attachment A, Tab A (Exhibit JH-1) and Tab N (Exhibit JH-5).
[5] NIPSCO Response to CAC Set 1-5 Attachment A, Tab A (Exhibit JH-3); NIPSCO Response to CAC 1-5 Supplemental Attachment A, Tab N (Exhibit JH-6).

It should be noted that between November 2010 and October 2015, NIPSCO charged its cash-strapped LIHEAP customers over $951,000 in late payment fees.[6]

Q. Why are low-income utility customers sometimes late in paying their utility bills?

A. For many family and household types, there is a lack of sufficient income to pay for the most basic necessities – housing, child care, food, health care, transportation, taxes, and personal care. Paying for expenses of a no-frills household budget is an arithmetic impossibility for many Hoosiers. According to the results of a recent report prepared for the Indiana Institute for Working Families, a single person living in Lake County needs $21,508 just to pay for the most basic necessities. This required income level is equal to 183% of the federal poverty guidelines.[7] The self-sufficiency standard, along with the corresponding ratio of income to poverty for various family types living in Lake County is illustrated below.

[6] NIPSCO Response to CAC Set 1-6 Supplemental Attachment A, Tab W (Exhibit JH-7).
[7] Pearce, "The Self-Sufficiency Standard for Indiana 2016," p. iv, January, 2016; HHS FY 2015 Federal Poverty Guidelines.

Table 1: Lake County Self-Sufficiency Standard

Household Type	One Adult	One Adult One Preschooler	One Adult One Preschooler One School-age	Two Adults One Preschooler One School-age
Lake County Self-sufficiency Income	$21,508	$39,431	$49,121	$56,006
Percent of 2015-2016 Federal Poverty Guideline	183%	248%	245%	279%

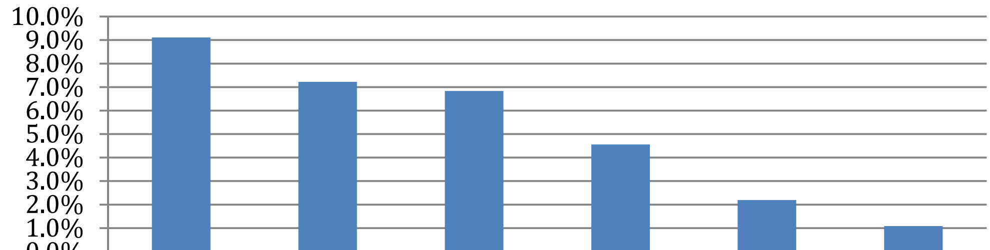
According to results of the U.S. Census Bureau's American Community Survey, in 2014, 30% of Lake County's families were living at or below 200% of the federal poverty guideline.[8] In light of the cost of basic necessities, as documented in the 2016 Self-Sufficiency Standard report, and the high number of households with insufficient income to meet those costs, as documented in the American Community Survey, utility affordability problems and challenges in making timely monthly payments become more easily understood.

In addition to lacking sufficient income to make ends meet each month, low-income households must devote a higher proportion of total household income to basic home electricity service than their higher-income counterparts. Based on the 2014 average NIPSCO residential customer electricity expenditure of $1,089,[9] a single, full-time minimum wage earner taking no time off for vacation or illness

[8] U.S. Census Bureau, 2014 American Community Survey, C17026.
[9] NIPSCO 2014 FERC Form 1, p. 304.

carried an electricity burden of 9.1%. Clearly, the burden is considerably higher for a customer using electric resistance heat. The burden for a 2-person household living at 150% of the 2014 federal poverty guideline[10] was 4.6%. By contrast, the electric burden for a household at Lake County, Indiana median income was 2.2% and about 1% for a higher-income household with income of $100,000. Thus, as illustrated below, a minimum wage worker must devote about 9 times the percentage of total income for home electric service as a higher-income household, raising an equity concern in light of the fact that electricity service is a basic necessity of life.

Graph 3: ***Unequal Burdens***
Electricity Expenditures as a Proportion of Household Income: Lake County. 2014



	2-person Household, 75% 2013 FPL	Single, minimum wage worker (40 hours x 52 weeks * $7.25)	2-person Household, 100% 2015 FPG	2-person Household, 150% 2015 FPG	2014 median income household - Lake County, IN	2014 upper-income household ($100,000)
Undiscounted Electricity Burden	9.1%	7.2%	6.8%	4.6%	2.2%	1.1%

[10] U.S. Department of Health and Human Services, http://aspe.hhs.gov/poverty/14poverty.cfm.

To summarize, examination of NIPSCO data reveals that the Company's low-income residential customers face late payment fee and disconnection notice rates that are much higher than those of general residential customers. We have seen that many lower-income households in Indiana lack sufficient income to make ends meet, yet must devote an inordinate proportion of these inadequate incomes to retain access to basic, necessary electric utility service. The affordability problems outlined above constitute a threat to the home energy security of NIPSCO's low-income customers and call for program and policy interventions to mitigate that threat.

III. COMPREHENSIVE LOW-INCOME BILL PAYMENT ASSISTANCE PROGRAM

Q. What programs and policies do you recommend as means of enhancing the home energy security of NIPSCO's low-income customers?

A. I recommend that the Commission direct NIPSCO to develop and make available a low-income rate that reduces low-income customers' payments to a more affordable level. In conjunction with a low-income rate, I recommend that the Company implement an arrearage management program that provides LIHEAP-eligible customers who carry an overdue balance with a reasonable opportunity to have those balances written down over time through timely payments on more affordable current bills.

Q. Please lay out policy objectives and program design principles of a low-income electricity affordability program.

A. Reliable electricity service is a necessity of life. Without electricity, residents cannot participate effectively in present-day society or be secure from threats to health and safety. All NIPSCO customers, including those with low incomes, should have access to reliable and secure sources of electricity. To help ensure energy security for low-income residents, what is needed is an electricity affordability program that:

- serves LIHEAP-eligible residential electricity customers at or below 150% of the federal poverty level,
- lowers program participants' electricity burdens to an affordable level,
- promotes regular, timely payment of electric bills by program participants,
- comprehensively addresses payment problems associated with program participants' current and past-due bills,
- is funded through a mechanism that is predictable while providing sufficient resources to meet policy objectives over an extended timeframe,
- is paid for by all classes of electricity customers, and
- is administered efficiently and effectively.

Q. Does the $50 LIHEAP credit proposed by NIPSCO meet the policy objectives that you have identified?

A. While the program proposed by Company Witness Shambo on behalf of the Company would provide a $50.00 credit on the June bills of residential electric service customers enrolled in LIHEAP and could be administered efficiently, it would not lower program participants' electricity burdens to an affordable level, promote regular, timely payment of electric bills by program participants, comprehensively addresses payment problems associated with program participants' current and past-due bills, be funded through a mechanism that is predictable while providing sufficient resources to meet policy objectives over an extended timeframe, and be paid for by all classes of electricity customers. Therefore, I recommend that the Company be directed to develop and implement a more robust program to meet these critical policy objectives.

Q. Please provide recommendations regarding eligibility guidelines, participation and enrollment.

A. Income eligibility for participation in NIPSCO's electricity affordability program should be capped at no less than the LIHEAP income-eligibility guideline – currently 150% of the federal poverty guideline. All households receiving benefits through the federal LIHEAP should be automatically enrolled in the electricity affordability program. In the event that the electricity affordability program's participation level does not exceed any enrollment ceiling that may be established, consenting households receiving benefits from other means-tested benefit programs (e.g., SNAP, Medicaid) should also be automatically enrolled in the electricity affordability program.

Q. Please provide recommendations regarding program benefits.

A. NIPSCO affordability program participants should receive benefits in the form of discounted electric rates or fixed credits on their electric bills. The goal of the program should be to substantially lower the electricity burden of participants. To meet these objectives, I recommend the Company be directed by the Commission to implement a discounted rate of 25% for LIHEAP-eligible electricity customers. In order to promote efficient use of energy resources, monthly discounts may be capped at a predetermined consumption level or bill credits may be fixed. Benefit levels could be capped based on weather-normalized, average electricity consumption at the participant's residence, or among all NIPSCO households with similar end-use needs (i.e., general appliance use only, general appliances and hot water, or general appliances, hot water and heat). However, such mechanisms should be carefully designed so that they do not result in unintended threats to the health and safety.[11]

Q. Please describe your recommendations regarding the incorporation of an arrearage management program design component.

[11] It should be noted that some high-use electricity customers may have little control over the thermal characteristics and appliances that are used in their houses or apartments. Other high-use customers may require electricity-driven equipment for medical purposes. In such cases, it is important that program design features do not provide customers with an incentive to under-consume in a manner that could prove harmful to health.

A. In order to enhance the effectiveness of discounts on current bills and promote timely program participant payments going forward, I recommend that NIPSCO implement an arrearage write-down, or management program, in conjunction with low-income rates.[12] Effectively promoting regular bill payment entails ensuring that *total* payments are affordable. A program that is intended to promote regular, timely payments by participants through reduction of electricity burdens to an affordable level is rendered less effective by a requirement that participants pay an amount in addition to the affordable current bill. Simultaneous payment of pre-existing arrears and the discounted electric bill therefore runs counter to the policy objective of promoting regular, timely payments by program participants. Accordingly, I recommend that NIPSCO's electricity affordability program include a component that provides for the retirement of pre-program arrears through 12 timely payments of discounted current bills.

There are two basic models of low-income utility arrearage management that have been implemented in the U.S. One entails the write-down of customer arrears over time after a series of timely payments on current bills. The other model entails the retirement of arrearage balances in full on a one-time basis. The one-

[12] CAC requested in CAC Data Request 1-6 that the Company provide monthly totals of LIHEAP electric residential service customers with unpaid account balances 60 to 90 days after issuance of a bill and 90 or more days after issuance of a bill. In addition, CAC requested that the Company provide the dollar value of those unpaid accounts. The Company objected to the requests and responded that it was unable to provide these data (attached as Exhibit JH-8). Therefore, in estimating the program costs, CAC must make assumptions about average participant pre-program arrears. For purposes of this analysis, I have assumed that the average past arrearage among NIPSCO's residential customers participating in LIHEAP to be $250.00.

time "forgiveness" model is administratively the simplest, but entails a large initial outlay of program cash resources. Write-down over a period of 12 months may provide customers with an enhanced incentive to keep up with current bills (as long as they are affordable), while placing less strain on program cash flow. I recommend that the Company implement an arrearage management program that provides low-income rate participants to write down one-twelfth (1/12) of a pre-program overdue balance with each timely payment of a current bill.

Q. Please describe your recommendations regarding program funding.

A. Funding for an electricity affordability program needs to meet sufficiency and predictability objectives. Program funding should be sufficient to provide meaningful energy burden reduction and energy security for electricity customers living below 150% of the federal poverty level. Lowering the electricity burdens and writing down pre-program arrears of the Company's customers participating in LIHEAP entails program benefit and administration costs of an estimated $13.7 million for the first year of program administration, as reflected in my work papers. This cost estimate is based on the Company's customer, sales and revenue data, as filed in the 2014 FERC Form 1, and on arrearage and LIHEAP customer data as provided by IPL in response to CAC data requests.[13] It should be noted that subsequent years of program operation will be substantially reduced to the extent that participant arrears are reduced. Finally, I added program

[13] NIPSCO 2014 FERC Form 1, p. 304.

administration costs of 5% of program benefits to the total program cost estimate, most of which should be provided by the non-utility organizations that determine LIHEAP eligibility. The estimated cost of the program proposed by Joint Intervenors represents 0.850% of the Company's revenues from sales to residential, commercial and industrial customers. A sustainable electricity affordability program with set benefit levels and participation rates also requires funding that is predictable and reliable. The most predictable, reliable source of funding for a sustainable electricity affordability program would come from a non-bypassable charge on monthly electric bills to all classes of customers. A uniform volumetric charge — approved prior to program implementation — would provide predictable program funding. Based on NIPSCO's 2014 sales of 17,363,000 mWh[14], the Joint Intervenors recommend that the Commission approve a charge of $0.00079 per kWh in addition to charges otherwise approved in this proceeding to fund low-income payment program costs.

Q. Please provide your recommendations regarding program administration and implementation.

A. Electricity affordability program design should foster efficient, streamlined administrative procedures. With limited program resources available, funds should be devoted to participant benefits rather than administrative costs to the greatest extent feasible. Minimizing administrative costs while delivering an

[14] NIPSCO 2014 FERC Form 1.

effective electricity affordability program will require that numerous agencies, organizations and individuals work together cooperatively and efficiently. I recommend that, whenever possible, administrative structures and procedures that apply to the State's LIHEAP be applied to the electricity affordability program.

The state's Community Action Agencies, with sufficient support from program administrative funds collected by the Company, are ideally suited to conduct program intake and outreach functions. The agencies that certify LIHEAP eligibility could then simultaneously certify low-income rate and arrearage management eligibility using the same procedures that currently apply to LIHEAP.

NIPSCO would be responsible for collecting program-related charges from all customers, and assigning qualified customers a low-income rate. NIPSCO would further be responsible for tracking arrearage write-down for each participating customer. The Company would also be responsible for regular reporting to the Commission of program activities and financial transactions. All program costs, including bill credits or discounts, approved startup and ongoing administrative expenses, and approved arrearage retirement amounts should be recoverable.

Affordability rate applicants would provide documentation required for certification on an annual basis. In addition, program applicants should be referred to all appropriate energy efficiency services that may be available.

Q. Why should the Commission approve the Joint Intervenors' recommendation that NIPSCO implement a low-income bill payment assistance program?

A. The recommended program design includes a number of advantageous elements. First, it would substantially enhance energy affordability for many of the Company's electricity consumers most vulnerable to the effects of high bills and unwelcome disconnection of electricity service. Table 2, below, illustrates examples of the electricity burden impact of the proposed program.

Table 2: Electric Burden Impact on 2-Person Household at Various HHS Poverty Guideline Levels and Carrying $250 Arrearage

	50% Poverty	***100% Poverty***	***Single, Minimum Wage earner***	***150% Poverty***
2-Person Household Annual Pretax Income	$7,965	$15,930	$15,080	$23,895
Household Monthly Pretax Income	$664	$1,328	$1,257	$1,991
Arrearage Payment ($250/4)	$62.50	$62.50	$62.50	$62.50
Undiscounted Annual Current Bill Electricity Expenditure	$1,089	$1,089	$1,089	$1,089
Undiscounted Monthly Current Bill Electricity Expenditure	90.75	90.75	90.75	90.75
Total Undiscounted Monthly Expenditure During Arrearage Payoff	$153.25	$153.25	$153.25	$153.25
Undiscounted Electricity Burden	23.09%	11.54%	12.19%	7.70%
Discounted Annual Current Bill Expenditure	$817	$817	$817	$817
Post-enrollment Arrearage Payment	$0	$0	$0	$0
Total Discounted Monthly Expenditure	$68	$68	$68	$68
Discounted Electricity Burden	10.25%	5.13%	5.42%	3.42%

It can be seen through this example how the program, as outlined above, reduces the hypothetical 2-person household at 100% of poverty from 11.5% of an undiscounted electricity burden during the period of arrearage payoff to a more manageable 5.1%. This enhanced affordability makes it more likely that the household will be able to retain uninterrupted access to necessary service and reduces the likelihood that the customer will be faced with collection activities such as receipt of disconnection notices and requirement to enter into a deferred payment agreement.

Related to the enhanced affordability benefit provided through the proposed program design is its comprehensive approach to dealing with participants' current bills and arrearage balances. Affordability objectives of energy assistance programs that fail to address pre-program arrears but discount current bills are undermined by the requirement that participants must add arrearage payoff to that of the current bill. In other words, a portion of the household energy burden reductions that come from discounted current bills must be "given back" as customers pay off outstanding balances. Similarly, energy assistance programs that focus entirely on retirement of arrears but not on the affordability of current bills are unlikely to result in long-term household energy security. If current bills are not affordable, there is a strong likelihood that arrears will simply re-accrue after balances are initially retired.

I propose that program outreach, intake and income certification functions be performed by Community Action Agencies that deliver WAP and LIHEAP to low-income households in Indiana. Those community-based entities should perform intake and certification functions under contract with NIPSCO. Such an arrangement would allow the program to "piggyback" onto LIHEAP and WAP, and utilize the administrative structures that have developed around those programs over decades. For example, given the overlap in income eligibility guidelines, a NIPSCO customer that is certified to receive benefits through LIHEAP could automatically be enrolled in the utility affordability program through electronic notification. This arrangement would eliminate the time and expense associated with separate intake and certification processes, and would enhance the benefits associated with both programs. To be successful, it is crucial that these entities receive sufficient program administrative funding collected by the Company in order to complete these important activities.

Q. What are the costs of implementing the program that you have proposed?

A. Projecting the cost of implementing the affordability program requires multiplying the number of program participants by the sum of the value of the monthly discount (or revenue loss) per customer and the average arrearage per customer that is retired. Program administration costs must then be added to the value of discounts and retired arrearages to obtain an estimate of total program costs. Response to CAC-Data Request 1-6 (<u>Exhibit JH-1</u>) indicates that during calendar year 2010, an average of nearly 25,000 of the Company's residential electric service customers were enrolled in LIHEAP. While the known LIHEAP participation rate among NIPSCO's residential electric service customers has declined in recent years, I applied the higher participation rate in estimating program cost to avoid underestimating total costs. I further assumed that program administrative costs would be 5% of the cost of discount and arrearage write-down benefits.

Q. Do electric utilities in other states provide ratepayer-funded bill payment assistance programs in the form of straight discounts?

A. Yes. California and Massachusetts have long operated such programs with great success. In fact, the program in Massachusetts operates in conjunction with an arrearage management program similar in design to the one proposed by the Joint Intervenors. Descriptions of low-income bill payment assistance programs may be found at the website of the LIHEAP Clearinghouse.[15]

IV. COLLECTION AND REPORTING OF TIME SERIES DATA ON RESIDENTIAL ARREARAGES, DISCONNECTIONS, AND UNCOLLECTIBLE ACCOUNT WRITE-OFFS

Q. Please describe the need for monthly collection and reporting of information regarding arrearages, service disconnections and other data points related to the home energy security of residential electricity consumers.

A. As demonstrated in testimony above, NIPSCO's low-income residential customers receiving benefits through LIHEAP, as well as many of NIPSCO's general residential customers not participating in LIHEAP, face serious payment

[15] http://www.liheapch.acf.hhs.gov/dereg.htm

difficulties and loss of essential home electricity service. Regular reporting of indicators of payment problems is required to assess on an ongoing basis the state of home energy security among NIPSCO's residential customers, and to evaluate the effectiveness of programs and policies intended to protect that security. Further, such data reporting is needed to assess the effectiveness of the credit and collection policies and practices of the Company, with an eye toward improving such practices when appropriate. Implementing a regular data collection and reporting protocol, in light of sweeping changes underway in energy and utility industry technology and economics – changes that have profound bearing on the energy security of the Company's most vulnerable customers – is particularly relevant and timely.

Indiana's regulators, policy-makers, consumers, and utility decision-makers are faced with difficult questions regarding the effectiveness of programs and policies designed to ensure regular payment for utility service while recognizing the essential nature of that service. Questions regarding appropriate expenditure for energy efficiency and payment assistance, the effectiveness of existing regulatory consumer protections and credit and collection practices can only be answered through data-driven analysis of trends in customer arrearages, service terminations and related indicators of the magnitude of utility payment troubles. Without timely trend data, it is not possible to appropriately respond to the payment troubles increasingly being experienced within the low-income population. It is, for example, unfeasible to satisfy one of the possible statutory criteria permitting the release of LIHEAP emergency contingency funds. The LIHEAP statute defines "emergency" to include "a significant increase in home energy disconnections reported by a utility, a State regulatory agency, or another agency with necessary data."[16]

State regulators and consumer advocates have recognized the need for collection of trend data on arrearages, disconnections and related points. In fact, both the National Association of Regulatory Utility Commissioners ("NARUC") and the National Association of State Utility Consumer Advocates ("NASUCA") adopted resolutions calling for the collection and reporting of this information. The 2007 NARUC Resolution is attached as Exhibit JH-9, and the 2011 NASUCA Resolution is attached as Exhibit JH-10.

Q. Please specify the data points and reporting protocol that are required to gauge the state of low-income and general residential home energy security in the NIPSCO Service Territory.

A. I recommend that the Commission direct the Company to, within six months of the Final Order in this proceeding, prepare, file with the Commission, and make available to the public monthly, in readily accessible spreadsheet format, the following data points:

[16] 42 U.S.C. § 8622(1)(D).

<u>General Residential Customers</u>

- Number of Residential Accounts
- Total Billed
- Total Receipts
- Total Number of "Protected" Accounts (e.g., for serious illness, elderly, disability)
- Number of Unpaid Accounts 60-90 Days after issuance of a bill
- Dollar Value of Unpaid Accounts 60-90 Days after issuance of a bill
- Number of Unpaid Accounts 90+ Days after issuance of a bill
- Dollar Value of Unpaid Accounts 90+ Days after issuance of a bill
- Total Number of Unpaid Accounts
- Total Dollar Value of Unpaid Accounts
- Number of Accounts Referred to Collection Agencies
- Number of New Payment Agreements
- Number of New Budget Billing Plans
- Number of Accounts Sent Notice of Disconnection for Non-payment
- Number of Service Disconnections for Non-payment
- Number of Service Restorations after Disconnection for Non-payment
- Average Duration of Service Disconnection for Restored Accounts
- Number of Accounts Written Off as Uncollectible
- Dollar Value of Accounts Written Off as Uncollectible
- Dollar Value of Recovered Bad Debt

<u>Low-income Customers</u>[17]

- Number of Accounts
- Total Billed
- Total Receipts
- Total Receipts Paid by LIHEAP
- Total Number of Customers Receiving LIHEAP
- Total Number of "Protected" Accounts (e.g., for serious illness, elderly, disability)
- Number of Unpaid Accounts 60-90 Days after issuance of a bill
- Dollar Value of Unpaid Accounts 60-90 Days after issuance of a bill
- Number of Unpaid Accounts 90+ Days after issuance of a bill

[17] "Low-income customers," as used in this context, refers to customers identified as participants in LIHEAP or other means-tested benefit programs.

- Dollar Value of Unpaid Accounts 90+ Days after issuance of a bill
- Total Number of Unpaid Accounts
- Total Dollar Value of Unpaid Accounts
- Number of Accounts Referred to Collection Agencies
- Number of New Payment Agreements
- Number of New Budget Billing Plans
- Number of Accounts Sent Notice of Disconnection for Non-payment
- Number of Service Disconnections for Non-payment
- Number of Service Restorations after Disconnection for Non-payment
- Average Duration of Service Disconnection for Restored Accounts
- Number of Accounts Written Off as Uncollectible
- Dollar Value of Accounts Written Off as Uncollectible
- Dollar Value of Recovered Bad Debt

I further recommend that Commission staff conduct a public technical session with NIPSCO and interested stakeholders during the design phase of the data collection and reporting protocol to ensure that resulting reports are of benefit to all parties.

Q. Please provide examples of reporting from other states that is similar to the protocol and data point selection that you have recommended.

A. In Ohio, electric and natural gas utilities have long collected and reported monthly data on arrearages, disconnections, and payment plans for general residential customers and those participating in the state's low-income Percentage of Income Payment Plan ("PIPP"). With respect to customers participating in the PIPP bill payment assistance program, Ohio utilities report monthly the number of accounts, billing and payment information, benefits from the PIPP, arrearage and usage information. For all residential customers, utilities report number of accounts, service disconnections and reconnections, duration of disconnections, and information regarding payment plans and security deposits. Pursuant to the state's annual Winter Reconnection Order docket, companies file a separate report on customers having service restored or avoiding disconnection through that policy. Ohio's data reporting templates, provided by Public Utilities Commission of Ohio staff, are attached as Exhibit JH-11. The Excel spreadsheet will also be provided in my work papers.

In Illinois, electric and natural gas utilities are required by rule to submit reports as required by the Commission. The Illinois rule states:

> Not later than February 20 and May 20 of each year, each gas and electric utility which has former customers affected by this Section shall file a report with the Commission providing statistical data concerning numbers of disconnections and reconnections involving utility service and deposits, and data concerning the dollar amounts involved in such transactions. The Commission shall notify each gas and electric utility prior to August 1 of each year concerning the information which is to be included in the report for the following heating season (Section 8-207 of the Act).[18]

Recent Illinois reporting templates are attached as Exhibit JH-12. The Excel spreadsheets will also be provided in my work papers.

In Pennsylvania, the Public Utility Commission (PA PUC) regulations[19] require that electric, natural gas and steam heat utilities file on a monthly basis information regarding residential customer accounts. Monthly information

[18] Illinois Administrative Code § 280.180(h).
[19] Monthly reporting requirements can be found in 52 PA Code § 56.231. Annual reporting requirements can be found in 52 PA Code § 62.5 and § 54.75.

includes arrearages by heating and non-heating usage, and dollar value and vintages of residential accounts in arrears. In addition, utilities provide monthly data on residential termination notices sent and personal contacts made with customers prior to termination. Companies also report on numbers of terminations completed by heating or non-heating usage, dollar value and vintage of arrears, and zip code. Reconnections are reported by usage type, by circumstances associated with reconnection (i.e., payment plan settlement between company and customer, presentation of a medical certificate, or through making payment in full). In addition to monthly data, utilities are required to report on an annual basis on the number of residential payment arrangements entered into, annual collection expenses incurred, dollar value of residential uncollectible write-offs, numbers of residential customers in arrears but not in payment agreements, and total number of low-income households served. The PA PUC produces and publicizes a detailed annual report presenting by company the information gathered pursuant to provisions in the PA Code. The most recent Pennsylvania report is attached as Exhibit JH-13.

In Iowa, provisions in their Administrative Code require that investor-owned electric[20] and natural gas[21] utilities report residential customer statistics to the Iowa Utilities Board (IUB) on a monthly basis. Since 1999, utilities have

[20] Iowa Admin. Code 199-20.2(5)(j).
[21] Iowa Admin. Code 199-19.2(5)(j).

reported monthly the number of accounts, the number of accounts in arrears, dollar amounts in arrears, disconnection notices issued, number of disconnections, number of reconnections, and uncollectible accounts. Except for disconnection and reconnection reporting, companies differentiate between general residential customers and those who have been deemed eligible for energy assistance benefits. The data collected by the IUB is available on the Board's website,[22] and are distributed to interested parties on a monthly basis. A recent Iowa report is attached as Exhibit JH-14. With regular reporting over a protracted period, long-term and short-term trends in home energy security may be observed,

V. NIPSCO'S Proposal to Increase Residential Customer Charges

Q. Please describe NIPSCO's proposal to recover embedded costs.

A. NIPSCO proposes to recover an increased portion of its embedded costs from residential customers through a dramatically increased monthly customer charge. As represented by the Company's witness, Mr. Shambo, NIPSCO proposes to increase the non-bypassable monthly fixed fee for residential Rate 711 by 82%, from \$11.00 to \$20.00.[23]

Q. What is your response to NIPSCO's residential rate design proposal?

A. Providing for utility cost recovery through rate modifications that increase customer charges while reducing cost recovery from volumetric charges penalizes

[22] https://iub.iowa.gov/moratorium-report
[23] Direct Testimony of Frank A. Shambo, Exhibit No. 17, Workpaper 17-J.1.

the low-volume consumers within a customer class. Dramatic increases in customer charges with reductions or only moderate increases in energy charges increases the total monthly bill of low-volume consumers by a higher percentage than that of higher volume consumers. In fact, the Company's proposed changes to Rate 711 would increase the monthly bill of a low-volume residential consumer using 200 kWh per month by over 28%, while a high volume user would see an increase of under 9%. This dynamic raises profound equity concerns in that it will cause disproportionate harm to low-income, elderly, and African American ratepayers, who on average use less electricity than their counterparts in nearly every region of the country. In addition, by shifting cost recovery from volumetric, energy charges to monthly customer charges, the Company's proposal would diminish the customer price incentive to participate in energy efficiency programs or otherwise make home energy efficiency improvements. The proposal would diminish the ability of customers to control their electric service bills.

Because adoption and implementation of the Company's proposal would unjustly shift costs and cause disproportionate harm to low-volume, low-income residential ratepayers while undermining the viability of energy efficiency programming, the Commission should reject the rate modification proposal and require that the Company redesign its rates with greater cost recovery emphasis on volumetric energy charges.

Q. Please describe the inequities of the Company's rate design proposal.

A. The Company's proposal, if approved, will disproportionately harm low-income, elderly, and African-American, electricity ratepayers. On average, low-income consumers in Indiana and Ohio – defined here as households living at or below 150% of the federal poverty level – use less electricity than the 2-state residential average and less than their higher-income counterparts. African-American headed households also use less than average. Similarly, households headed by an elder – defined here as a person 65 years of age or more – use considerably less electricity than the 2-state average and less than non-elder households. Thus, the Company's proposal, if approved, will disproportionately harm these groups by increasing their bills by a higher percentage than average.

The tables below illustrate that on average, low-income households in Indiana and Ohio use 27.7% less electricity than their higher-income counterparts. Households headed by an individual of African-American descent, on average, use 24.6% less electricity than households headed by a Caucasian. Elder households use 48.4% less electricity than non-elder households.

Table 3: 2009 Median Household Electricity Usage by Poverty 150% Status - Indiana and Ohio

	Total Site Electricity usage, in kilowatt-hours	Percent Difference
Income At or Below 150% Poverty	7,831	-27.7%
Income Above 150% Poverty	9,999	
Total	9,365	

Source: Energy Information Administration, 2009 Residential Energy Consumption Survey

Table 4: 2009 Median Household Electricity Usage by Race of Householder - Indiana and Ohio

Householder's Race	Total Site Electricity usage, in kilowatt-hours, 2009	Percent Difference
Black or African/American	7,900	-24.6%
Caucasian	9,846	

Source: Energy Information Administration, 2009 Residential Energy Consumption Survey

Table 5: Median Household Electricity Usage by Elder Status - Indiana and Ohio

Householder's Race	Total Site Electricity usage, in kilowatt-hours, 2009	Percent Difference
65 or More	6,976	-48.4%
Less than 65	10,351	

Source: Energy Information Administration, 2009 Residential Energy Consumption Survey

Q. Please describe the methodology that you used to generate consumption tables and charts.

A. I generated electricity usage tables and graphs using microdata from the U.S. Department of Energy, Energy Information Administration 2009 Residential Energy Consumption Survey ("RECS"). The 2009 RECS includes detailed residential energy consumption and expenditure information from 27 U.S. geographic areas referred to as "reportable domains." Indiana and Ohio comprises one of the reportable domains.[24]

The RECS survey instrument includes questions regarding a broad range of demographic factors and household characteristics. Using SPSS statistical software, I sorted RECS data to generate cross-tabulations of kilowatt-hour usage by poverty status, race, and age of householder.

Results of these analyses clearly demonstrate that in the Indiana-Ohio reportable domain – on average – low-income, African American, and elderly households use less electricity than their counterparts. As indicated above, the Company's proposal, by penalizing low-volume consumers, will disproportionately harm these groups of rate payers.

[24] The RECS results cannot be sorted to provide results that apply specifically to an individual utility service territory. However, it should be noted that while the electricity usage among subgroups of residential consumers in the Company's service territory may vary somewhat from the 2-state average usage, the relative usage patterns\identified in The Indiana-Ohio region are highly consistent with those from other geographic regions across the U.S. It is therefore reasonable to assume that the general usage patterns identified in Indiana-Ohio – and throughout the U.S. – apply to the NIPSCO service territory.

Q. Please respond to the Company's assertion that NIPSCO low-income residential customers use less electricity than higher non-low-income residential customers.

A. RECS provides the most reliable national data reflecting electricity consumption of all low-income households – not just those that participate in federal or utility bill payment assistance or energy efficiency programs. The data demonstrates conclusively that in 27 of 28 regions surveyed, median average electricity consumption among households living at or below 150% of the federal poverty guidelines is less than that of higher-income households. Table 6, below, reflects this consistent pattern.

Table 6: Median 2009 Site Electricity Usage (kWh), by 150% Poverty Status

	< = 150% Poverty	Above 150% Poverty	All Households	% Difference
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	4,708	7,468	6,961	-58.60%
Massachusetts	4,222	6,056	5,686	-43.40%
New York	4,544	5,969	5,355	-31.40%
New Jersey	4,969	7,497	7,231	-50.90%
Pennsylvania	8,402	9,690	9,306	-15.30%
Illinois	7,350	9,116	8,432	-24.00%
Indiana, Ohio	7,831	9,999	9,365	-27.70%
Michigan	7,073	8,190	7,764	-15.80%
Wisconsin	7,449	7,889	7,727	-5.90%
Iowa, Minnesota, North Dakota, South Dakota	6,241	9,285	8,940	-48.80%
Kansas, Nebraska	8,808	9,402	9,302	-6.70%
Missouri	11,705	12,232	11,991	-4.50%

Virginia	10,997	13,859	13,231	-26.00%
Delaware, District of Columbia, Maryland, West Virginia	10,381	13,063	12,848	-25.80%
Georgia	12,727	13,816	13,499	-8.60%
North Carolina, South Carolina	12,105	14,343	13,651	-18.50%
Florida	11,905	13,760	13,212	-15.60%
Alabama, Kentucky, Mississippi	11,802	15,847	14,656	-34.30%
Tennessee	12,537	14,480	13,782	-15.50%
Arkansas, Louisiana, Oklahoma	12,628	13,646	13,421	-8.10%
Texas	10,602	13,799	12,878	-30.20%
Colorado	5,216	6,516	6,231	-24.90%
Idaho, Montana, Utah, Wyoming	10,665	9,588	9,804	10.10%
Arizona	10,088	13,056	12,105	-29.40%
Nevada, New Mexico	7,637	9,434	9,164	-23.50%
California	4,739	5,939	5,628	-25.30%
Alaska, Hawaii, Oregon, Washington	10,597	10,799	10,754	-1.90%
Total	8,432	10,072	9,687	-19.40%

Source: Tabulated by National Consumer Law Center using U.S. Energy Information Administration 2009 Residential Energy Consumption Survey

The Company bases its assertion of lower electricity usage among NIPSCO low-income residential customers on a bill distribution provided in NIPSCO Exhibit No. 2, Attachment 2-C. It is important to note that the evidence provided by the Company appears to be based on data pertaining to utility customers participating in energy assistance programs. However, such programs cannot be used reliably as proxies for the entire universe of low-income households. If reported consumption levels are based on utility program participants, a concern arises that the low-income results are biased on the high side, assuming that utility programs are often targeted toward high use/high bill customers, and in the case of low-income energy efficiency programs, to homeowners rather than renters and multi-family dwellers whose electricity usage tends to be relatively low. Given the consistency of the regional RECS consumption data and the narrow sample of low-income customers that NIPSCO relies on for its analysis, it is inappropriate to conclude that NIPSCO low-income residential customers use less than their counterparts.

Q. How do high customer charges affect energy efficiency?

A. The Company's proposal, by shifting costs away from volumetric charges and onto the fixed, customer charge, would undermine the price incentive to reduce usage and participate in general residential energy efficiency programs and, for income-eligible customers, the federal Weatherization Assistance Program. Such programs, operating in conjunction with effective regulatory consumer protections and bill payment assistance, comprise the cornerstone of long-term, low-income home energy security. Further, increasing fixed charges undermines the ability of customers to control their bills, which constitutes a particular problem for low-income households that struggle with affordability and electricity burden problems, as outlined above.

In summary, adoption and implementation of the Company's proposal would unjustly shift costs from high-volume to low-volume consumers and cause disproportionate harm to low-income, African-American, and elderly households and individuals. Further, if approved and implemented, the Company's customer charge proposal will undermine the viability of energy efficiency programming critical to low-income home energy security in the long term. Therefore, I recommend that the Commission reject the Company's rate modification proposal.

VI. Conclusion

Q. Please summarize your conclusions and recommendations.

- Review of data provided to CAC in response to data requests revealed that, relative to non-low-income general residential customers, low-income customers in the NIPSCO service territory experience bill payment difficulties and experience high rates of late payment fees and notices of service disconnection.
- Low-income bill payment challenges experienced by NIPSCO's low-income customers are partially explained through examination of federal poverty guidelines, data relative to income required by various family types to pay for basic necessities, and residential customer expenditure data. Review of these data sets demonstrates that low-income households carry heavy home electricity burdens, much higher than those households with more stable, higher income. For example, a 2-person household

living at 75% of the federal poverty guideline shoulders a home electricity burden about 9 times higher than a household with an annual income of $100,000. Yet, basic electricity service is no less essential for that low-income household that struggles just to keep the lights on.

- In the face of the evidence referenced above, I recommend that the Commission direct NIPSCO to develop and make available a low-income rate that reduces low-income LIHEAP-eligible customers' payments to a more affordable level by discounting total bills by 25%. In conjunction with a low-income rate, I recommend that the Company implement an arrearage management program that provides LIHEAP-eligible customers who carry an overdue balance with a reasonable opportunity to have those balances written down over time through timely payments on more affordable current bills. I further recommend that a new bill payment assistance program's administrative functions related to intake, income certification and outreach be handled by the local Community Action Agencies that currently perform those functions in the implementation of LIHEAP. Local Community Action Agencies should also receive sufficient funding to perform such functions. The new program should be designed to meet the following objectives:
    - serves LIHEAP-eligible residential electricity customers at or below 150% of the federal poverty level,

- lowers program participants' electricity burdens to an affordable level,
- promotes regular, timely payment of electric bills by program participants,
- comprehensively addresses payment problems associated with program participants' current and past-due bills,
- is funded through a mechanism that is predictable while providing sufficient resources to meet policy objectives over an extended timeframe,
- is paid for by all classes of electricity customers, and
- is administered efficiently and effectively.

- I recommend that the Commission approve a charge of $0.00079 per kWh in addition to charges otherwise approved in this proceeding to fund low-income payment program costs to fund a $13.7M program.
- For reasons stated in my testimony, I recommend that the Commission direct the Company to, within six months of the Final Order in this proceeding, prepare, file with the Commission, and make available to the public monthly, in readily accessible spreadsheet format, the following data points:

<u>General Residential Customers</u>

- Number of Residential Accounts
- Total Billed
- Total Receipts
- Total Number of "Protected" Accounts (e.g., for serious illness, elderly, disability)
- Number of Unpaid Accounts 60-90 Days after issuance of a bill
- Dollar Value of Unpaid Accounts 60-90 Days after issuance of a bill
- Number of Unpaid Accounts 90+ Days after issuance of a bill
- Dollar Value of Unpaid Accounts 90+ Days after issuance of a bill
- Total Number of Unpaid Accounts

- Total Dollar Value of Unpaid Accounts
- Number of Accounts Referred to Collection Agencies
- Number of New Payment Agreements
- Number of New Budget Billing Plans
- Number of Accounts Sent Notice of Disconnection for Non-payment
- Number of Service Disconnections for Non-payment
- Number of Service Restorations after Disconnection for Non-payment
- Average Duration of Service Disconnection for Restored Accounts
- Number of Accounts Written Off as Uncollectible
- Dollar Value of Accounts Written Off as Uncollectible
- Dollar Value of Recovered Bad Debt

<u>Low Income Customers</u>

- Number of Accounts
- Total Billed
- Total Receipts
- Total Receipts Paid by LIHEAP
- Total Number of Customers Receiving LIHEAP
- Total Number of "Protected" Accounts (e.g., for serious illness, elderly, disability)
- Number of Unpaid Accounts 60-90 Days after issuance of a bill
- Dollar Value of Unpaid Accounts 60-90 Days after issuance of a bill
- Number of Unpaid Accounts 90+ Days after issuance of a bill
- Dollar Value of Unpaid Accounts 90+ Days after issuance of a bill
- Total Number of Unpaid Accounts
- Total Dollar Value of Unpaid Accounts
- Number of Accounts Referred to Collection Agencies
- Number of New Payment Agreements
- Number of New Budget Billing Plans
- Number of Accounts Sent Notice of Disconnection for Non-payment
- Number of Service Disconnections for Non-payment
- Number of Service Restorations after Disconnection for Non-payment
- Average Duration of Service Disconnection for Restored Accounts
- Number of Accounts Written Off as Uncollectible
- Dollar Value of Accounts Written Off as Uncollectible
- Dollar Value of Recovered Bad Debt

- I further recommend that Commission staff conduct a public technical session with NIPSCO and interested stakeholders during the design phase of the data collection and reporting protocol to ensure that resulting reports are of benefit to all parties.
- Analysis of the U.S. Energy Information Administration's Residential Energy Consumption Survey data reveals that low-income, African-American and elder households use less electricity than their counterparts, and are therefore disproportionately harmed by shifting utility cost recovery from volumetric to monthly customer charges. NIPSCO's bill impact analysis confirms that low-usage customers would experience greater percentage of bill increases were the proposed rate design to be approved. In light of evidence presented in this testimony regarding low-income payment difficulties and home energy insecurity, and further evidence pointing to relatively low usage among low-income, African-American and elder customers, I recommend that the Commission reject the NIPSCO proposals to increase customer charges.

Q. **Does this conclude your testimony?**

A. Yes.

VERIFICATION

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

J Howat

_______________________________ January 22, 2016

John Howat Date

EXHIBIT JH-1

	A	B	C	D	E	F	G
1	**With respect to Low-income Residential Customers, (defined here as customers who participate in the Low Income Home Energy Assistance program, the Weatherization Assistance Program, any ratepayer- funded assistance or arrearage management program, or any low-income ratepayer-funded DSM program), please provide monthly figures since January 2010 for each of the data points listed below:**						
2							
3	**a. Total number of accounts**						
4	**Response:** The table below represents the monthly count of active residential electric LIHEAP accounts receiving service. This count includes customer accounts with more than one electric service.						
5							
6		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
7	January		20,122	13,902	12,435	11,211	10,897
8	February		24,215	17,643	16,184	14,971	13,981
9	March		27,084	20,041	18,332	17,781	16,249
10	April		27,922	21,097	19,541	19,170	17,311
11	May		28,103	21,450	20,192	19,714	17,805
12	June		27,886	21,399	20,185	19,638	17,858
13	July		28,121	21,290	20,144	19,330	17,679
14	August		27,989	21,088	19,920	19,018	17,508
15	September		27,555	20,958	19,704	18,702	17,295
16	October		27,048	20,664	19,395	18,411	17,187
17	November	9,080	5,042	4,005	2,103	1,847	1,018
18	December	15,460	9,443	7,721	7,357	6,859	

EXHIBIT JH-2

With respect to Low-income Residential Customers, (defined here as customers who participate in the Low Income Home Energy Assistance program, the Weatherization Assistance Program, any ratepayer- funded assistance or arrearage management program, or any low-income ratepayer-funded DSM program), please provide monthly figures since January 2010 for each of the data points listed below:

V. total number of customers charged a late payment fee

Response: The table below shows the dollar value of late payment charges for residential electric LIHEAP accounts by month.

MONTH	2010	2011	2012	2013	2014	2015
January		2,344	3,350	2,286	2,481	2,912
February		3,485	4,924	3,834	3,609	4,525
March		5,404	7,464	6,112	6,518	6,581
April		5,989	7,864	8,059	7,357	7,185
May		9,695	8,732	8,150	8,291	7,224
June		11,586	6,527	6,209	8,172	6,873
July		2,209	6,207	5,029	8,549	3,068
August		2,058	8,214	8,541	8,495	5,003
September		12,111	3,366	8,433	8,530	6,314
October		11,819	8,470	8,182	7,637	3,987
November	206	390	569	208	292	
December	508	1,327	572	586	608	

EXHIBIT JH-3

	A	B	C	D	E	F	G
1	**With respect to General Residential Customers, please provide monthly figures, since January 2010 for each of the data points listed below:**						
2							
3	**a. Total number of accounts**						
4	**Response:** The table below shows the monthly count of active accounts receiving residential electric service. This count includes customer accounts with more than one electric service.						
5							
6							
7							
8		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
9	**January**	384,245	385,177	384,821	385,310	386,144	386,550
10	**February**	384,707	385,469	385,199	385,640	386,392	387,158
11	**March**	384,849	385,206	384,980	385,619	386,380	387,060
12	**April**	384,785	384,907	385,001	385,566	386,005	386,869
13	**May**	384,775	384,850	384,950	385,360	385,456	386,602
14	**June**	384,801	384,480	384,764	385,140	385,373	386,707
15	**July**	384,485	384,150	384,833	384,958	385,178	386,772
16	**August**	384,688	384,149	384,841	384,831	385,260	386,742
17	**September**	384,554	384,219	384,615	384,916	385,221	
18	**October**	384,632	384,380	384,821	385,054	385,545	
19	**November**	384,956	384,564	385,036	385,444	386,259	
20	**December**	385,196	384,953	385,323	385,834	386,410	

EXHIBIT JH-4

	A	B	C	D	E	F	G
1	**With respect to General Residential Customers, please provide monthly figures, since January 2010 for each of the data points listed below:**						
2							
3	**v. Total number of customers charged a late payment fee**						
4	**Response:** The table below shows residential electric customers charged a late payment feeby month.						
5							
6		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
7	**January**	71,120	78,381	82,405	91,742	87,734	94,201
8	**February**	65,498	67,320	77,291	76,354	77,006	78,453
9	**March**	74,910	75,948	83,546	74,928	74,923	85,757
10	**April**	71,388	65,015	77,703	87,388	75,088	83,004
11	**May**	66,246	82,746	83,456	81,786	85,026	78,308
12	**June**	73,093	80,449	78,810	68,936	78,536	79,853
13	**July**	69,612	60,668	82,737	81,211	83,222	75,432
14	**August**	73,487	80,653	93,654	85,708	81,631	79,132
15	**Septembe**	73,067	84,938	72,445	79,290	84,245	
16	**October**	72,877	82,313	93,743	88,780	91,025	
17	**November**	69,769	72,439	81,865	74,929	71,141	
18	**December**	71,962	79,155	73,871	80,208	79,685	

EXHIBIT JH-5

	A	B	C	D	E	F	G
1	**With respect to Low-income Residential Customers, (defined here as customers who participate in the Low Income Home Energy Assistance program, the Weatherization Assistance Program, any ratepayer- funded assistance or arrearage management program, or any low-income ratepayer-funded DSM program), please provide monthly figures since January 2010 for each of the data points listed below:**						
2							
3	**n. Number of accounts sent a notice of disconnection for non-payment**						
4	**Response:** The table below represents the residential electric LIHEAP customers that were sent a notice of disconnection for non-payment.						
5							
6							
7	**MONTH**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
8	January		198	102	113	82	93
9	February		1,106	592	142	885	1,017
10	March		10,447	8,092	6,678	6,292	6,314
11	April		6,532	4,720	5,247	4,975	4,375
12	May		6,660	4,413	5,142	4,833	4,163
13	June		6,348	4,166	3,784	4,341	3,502
14	July		3,853	3,574	3,672	4,909	2,520
15	August		7,163	5,443	4,378	5,311	3,171
16	September		6,777	3,183	4,654	4,985	3,852
17	October		6,088	4,504	4,292	4,523	2,429
18	November	770	734	573	347	417	5
19	December	151	85	49	55	53	

EXHIBIT JH-6

With respect to General Residential Customers, please provide monthly figures, since January 2010 for each of the data points listed below:

n. Number of accounts sent a notice of disconnection for non-payment

Response: The table below reflects the total number of all electric residential customers that were sent a notice of disconnection for non-payment.

MONTH	2010	2011	2012	2013	2014	2015
January	31,599	40,067	42,386	43,531	45,591	40,405
February	30,079	31,624	33,514	34,120	38,138	40,670
March	40,578	46,781	44,223	42,335	43,773	45,650
April	34,621	36,883	37,892	43,453	41,199	41,474
May	29,762	39,387	32,219	39,975	40,001	36,981
June	31,960	36,512	34,444	33,740	35,938	34,848
July	35,850	35,177	35,971	38,976	39,805	35,746
August	40,516	40,797	46,518	37,839	41,844	36,974
September	40,469	42,555	36,273	39,446	41,449	39,232
October	35,583	33,756	39,531	36,490	41,075	36,876
November	30,086	33,069	33,907	32,097	29,914	29,501
December	34,381	34,926	34,801	36,234	39,570	

EXHIBIT JH-7

	A	B	C	D	E	F	G
1	**With respect to Low-income Residential Customers, (defined here as customers who participate in the Low Income Home Energy Assistance program, the Weatherization Assistance Program, any ratepayer- funded assistance or arrearage management program, or any low-income ratepayer-funded DSM program), please provide monthly figures since January 2010 for each of the data points listed below:**						
2							
3	**W. Total dollar value of late payment charges**						
4	**Response:** The table below shows the dollar value of late payment charges for residential electric LIHEAP accounts by month.						
5							
6	**MONTH**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
7	January		7,545	9,613	7,202	8,471	9,996
8	February		11,642	15,310	13,533	12,930	16,379
9	March		18,920	25,096	22,482	22,273	24,245
10	April		17,186	20,632	26,335	23,356	21,318
11	May		25,251	20,390	21,756	23,354	17,229
12	June		26,328	14,210	14,135	18,821	13,155
13	July		4,681	15,984	11,944	23,182	7,024
14	August		6,185	30,596	27,281	26,184	14,573
15	September		48,174	9,189	24,133	26,011	19,841
16	October		32,808	25,228	23,946	23,421	10,261
17	November	219	717	1,081	377	621	
18	December	1,058	3,211	1,430	1,331	1,566	

EXHIBIT JH-8

<u>CAC Request 1-006:</u>
With respect to Low-income Residential Customers (defined here as customers who participate in the Low Income Home Energy Assistance Program, the Weatherization Assistance Program, any ratepayer-funded bill payment assistance or arrearage management program, or any low-income ratepayer-funded DSM program), please provide monthly figures since January 2010 for each of the data points listed below: a. Total number of accounts b. Total billing c. Total receipts d. Total number of Protected Accounts   i. For Protected Accounts, please disaggregate by reason for protection (e.g., financial hardship, serious illness, disability or age status, etc.) e. Number of unpaid accounts 60-90 days after issuance of a bill f. Dollar value of unpaid accounts 60-90 days after issuance of a bill g. Number of unpaid accounts 90+ days after issuance of a bill h. Dollar value of unpaid accounts 90+ days after issuance of a bill i. Total number of unpaid accounts j. Total dollar value of unpaid accounts k. Number of accounts referred to collection agencies l. Number of new payment agreements entered into m. Number of new budget or levelized plans entered into n. Number of accounts sent notice of disconnection for non-payment o. Number of service disconnections for non-payment p. Ratio of service disconnections for nonpayment to total Residential Customers q. Number of service restorations r. Average duration of service disconnection for restored accounts s. Number of accounts classified as Bad Debt t. Dollar value of accounts classified as Bad Debt u. Dollar value of recovered Bad Debt v. Total number of customers charged a late payment fee w. Total dollar value of late payment charges
<u>Objections:</u>
NIPSCO objects to this Request on the grounds and to the extent that the Request is

vague and ambiguous as the term "Protected Accounts" is undefined. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that the Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing, as our CIS system does not denote low income customers. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that such Request is overly broad and unduly burdensome.
<u>Response:</u>
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: a, b, d, s, t, v, w) Please see the file attached hereto as CAC Set 1-006 Attachment A. c, e-r, u) The information requested cannot be independently tracked in NIPSCO's CIS system. Please also see NIPSCO's response to CAC Set 1-005.
<u>Supplemental Response:</u>
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: a, b, c, k, l, m, n, o, p, q, s, t, u, v, w) Please see the file attached hereto as CAC Set 1-006 Attachment A (Supplemental). e, f ,g ,h, i, j, r) The information requested cannot be independently tracked in NIPSCO's CIS system.

EXHIBIT JH-9

Resolution Supporting the Gathering of Data for Electric and Natural Gas Distribution Companies by Individual State Utility Commissions or Energy Offices

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC) recognizes the importance of gathering comparable aggregate residential billing and arrearage data to quantify the extent of customer indebtedness to utilities and the financial impact of customer indebtedness on utilities; to support State and federal low-income assistance programs, such as LIHEAP; and to evaluate the impact on customer affordability of essential electric and natural gas service; *and*

WHEREAS, The lack of wide-ranging billing and arrearage data has made it more difficult for many consumer groups, legislative offices and commissions to quantify the magnitude of the problem of non-payment for consumers; *and*

WHEREAS, The wide-ranging data compiled would be of great assistance to formulate State and national policies to assure affordable electric and natural gas service for residential customers, and to support programs which are necessary to the health, safety and welfare of American households; *and*

WHEREAS, The data compiled would provide State and federal policymakers with the tools needed to evaluate and ensure that federal energy assistance funds, such as LIHEAP, are adequate to meet utility-related emergencies due to increases in energy prices and/or weather related emergencies; *and*

WHEREAS, Based on survey data compiled by the NRRI/NARUC Staff Subcommittee on Consumer Affairs in 2002 and 2004, although there are at least eighteen States that are known to collect and report such data, it is necessary to have more comparable and inclusive data for the entire nation; *and*

WHEREAS, The compilation of comparable, periodic billing and arrearage data for residential customers over time would be very beneficial to State and federal policymakers to evaluate the impact of market conditions, higher energy prices, and weather conditions; evaluate the need for additional targeted financial assistance and energy management programs, as well as the need for review of State commission policies and practices to protect seniors and low-income customers; *and*

WHEREAS, NARUC recognizes that the National Association of State Utility Consumer Advocates (NASUCA), National Energy Assistance Directors Association (NEADA), Consumers Union, Consumer Federation of America, National Consumer Law Center (NCLC), National Low Income Energy Consortium (NLIEC), and the AARP (formerly the American Association of Retired Persons) support this resolution; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its February 2006 Winter Meetings in Washington, D.C., urges each individual State to gather relevant utility billing and arrearage data from all electric and gas utilities within its State commission jurisdiction and encourages other providers of electric and gas to work cooperatively with their State commission to provide necessary aggregate data; *and be it further*

RESOLVED, That NARUC directs the Staff Subcommittee on Consumer Affairs to form a collaborative workgroup with all interested stakeholders to design a survey template and a data dictionary of terms, and to urge each State to use and distribute the data dictionary and survey to all the utility companies within its State; *and be it further*

RESOLVED, That NARUC urges each State commission or energy office to generate a list of commission or energy office contacts for this project; *and be it further*

RESOLVED, That NARUC urges each State commission or energy office to direct utility companies to forward all questions about the project to its Commission contact, who in turn, will then forward the questions to the Staff Subcommittee on Consumer Affairs or its designee in order to ensure the consistency of data collection; *and be it further*

RESOLVED, That NARUC urges each State commission or energy office to aggregate the company level data into appropriate industry summary level data and submit it to the Staff Subcommittee on Consumer Affairs or its designee for analysis; and urges each State commission or energy office contact to document all variations and exceptions in the data and submit it for analysis; *and be it further*

RESOLVED, That affected stakeholders be allowed an opportunity to review the data analysis and derived conclusions prior to publication in order to provide clarification and ensure consistency.

Sponsored by the Consumer Affairs Committee
Adopted by the NARUC Board of Directors February 15, 2006

EXHIBIT JH-10

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

RESOLUTION 2011-2

URGING STATES TO GATHER UNIFORM STATISTICAL DATA ON BILLINGS, ARREARAGES AND DISCONNECTIONS OF RESIDENTIAL GAS AND ELECTRIC SERVICES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has passed a companion resolution encouraging the states to institute programs to reduce the incidence of disconnection of residential gas and electric service based on nonpayment; and

Whereas, gathering data concerning residential gas and electric service, including data concerning billings, arrearages and disconnections, and making that data publicly available, will assist policymakers in evaluating the effectiveness of existing disconnection practices and in identifying problems that may require new practices and policies; and

Whereas, the collection of arrearage and disconnection data concerning at-risk segments of the population including low-income customers, the elderly, and the ill are necessary to ensure that public health and safety risks are being adequately considered; and

Whereas, consistent, uniform reporting by utilities of billing and arrearage data enables policymakers to quantify both the number of consumers who are experiencing problems in paying their utility bills and the financial impact of the arrearages[1]; and

Whereas, the compilation of billing and arrearage data assists policymakers in evaluating the adequacy of financial assistance programs, such as the Low Income Home Energy Assistance Program (LIHEAP) and other government assistance programs, utility fuel funds, and community assistance resources in helping customers pay utility bills;[2] and

Whereas, a lack of consistent reporting of billing and arrearage data impedes the identification and/or aggregation of credit and collection best practices and the adoption of credit and collection benchmark standards that can be used in the States; and

Whereas, public policy supports the development of cost effective credit and collection policies and practices[3] that make disconnection of gas and electric services the remedy of last resort, occurring only after all other reasonable collection tools have been exhausted; and

Whereas, data regarding the imposition of cash deposits is necessary to evaluate their effectiveness and whether alternative methods should be used to help consumers demonstrate creditworthiness; and

Whereas, the collection of data concerning the additional charges and fees such as late payment charges, deposits, third-party fees for credit card or electronic payments, and reconnection charges are measures of the impact that customers are experiencing paying utility bills; and

Whereas, evaluations concerning the design and effectiveness of payment extensions and multi-month payment plans, including the number of disconnections avoided through the use of payment plans, can be performed much more effectively when there is a basis for evaluation through quantitative data uniformly reported across comparable utilities; and

Whereas, data concerning the length of time that customers are living without gas and or electric services following disconnections for non-payment is indicative of the difficulty consumers are experiencing securing access to continuous, essential utility services; and

Whereas, the National Association of Regulatory Utility Commissioners ("NARUC")

has previously passed a resolution4 supporting the gathering of terminations and arrearages data, including an emphasis on bringing interested stakeholders to the process of developing strategies for using such data effectively;

Now, therefore, be it resolved, that NASUCA urges the states to collect uniform data on gas and electric billing, arrearages and disconnections;

Be it further resolved, that NASUCA urges the states to adopt uniform reporting standards, enabled by reporting category requirements that are carefully defined and explained, such that commissions and advocates can view the data obtained from separate utilities for each reporting category alongside other utilities within the same industry, and draw not only utility-specific conclusions but industry-wide conclusions by aggregating the data, regarding the effectiveness or impact of specific disconnection, credit and collection practices or policies;

Be it further resolved, that NASUCA supports the collection and reporting of publicly available data on billings, arrearages and collections that enables an understanding of issues of affordability impacting customers in paying utility bills and the effectiveness of available resources to help consumers;

Be it further resolved, that NASUCA supports the collection and reporting of data on billing arrearages and disconnections that is timely enough for prompt analysis as needed;

Be it further resolved, that NASUCA supports the accessibility of uniform and reliably collected disconnections, credit and collection, billing and arrearages data to enable commissions and advocates to better evaluate credit and collection policies and practices, and setting and adopting benchmark standards and best practices;

Be it further resolved, that NASUCA supports the uniform gathering of the following defined data by the states on an annual basis:

a. number of residential customers who were required to pay a deposit to demonstrate creditworthiness to initiate gas or electric service and the average amount of the deposit;

b. number of residential customers who used alternative methods to a deposit to demonstrate financial responsibility while initiating service;

c. number of residential customers who were required to pay a deposit to initiate gas or electric service but were unable to do so;

d. number of customers enrolled in each specific and distinct low-income payment plan;

e. average payment amount for customers in each specific and distinct low-income payment plan;

f. number of customers enrolled in every other type of payment plans offered by the utility to other (non-low-income) customers;

g. the aggregate dollar amount that is being deferred in each specific and distinct type of low-income or other payment plan;

h. the aggregate dollar amount that has been collected in each specific and distinct type of low-income and other payment plan;

i. number of customers who defaulted on each specific and distinct type of payment plan;

j. provide the dollar value and number of residential accounts (and low-income accounts) written off as gross uncollectibles, in that the accounts have been written off and sent to a collection agency;

k. the dollar value and number of residential accounts (and low-income accounts) written off as net uncollectibles, in that the accounts have been written off after a collection agency has failed to collect payment;

l. separately provide the total number of accounts in arrears between 30 – 60 days, 60 – 90 days, more than 90 days;

m. separately provide the total dollar amount of the arrears that were owed between 30 – 60 days, 60 -90 days, more than 90 days;

n. number of residential customers receiving a disconnection notice;

o. number of low-income customers receiving a disconnection notice;

p. number of residential customers disconnected for non-payment;

q. number of low-income customers disconnected for nonpayment;

r. number of customers enrolled in a low-income payment assistance program when they were disconnected for non-payment;

s. number of residential customers who used special medical certification procedures to avoid disconnection;

t. separately provide the number of residential disconnections, and low-income residential disconnections, where service was reconnected within ten business days, ten to thirty days, thirty to sixty days, sixty to ninety days, and greater than ninety days.

Be it further resolved, that NASUCA supports the gathering and reporting of information related to the number of residential customers who received LIHEAP, fuel funds, or other financial assistance and the average amount of assistance received;

Be it further resolved, that NASUCA supports the gathering and reporting of the additional charges and fees that consumers pay on an annual basis to pay utility bills

a. to pay bills at authorized agents of the utilities;

b. to pay bills via credit cards or electronic checks;

c. in late payment charges;

d. in reconnection charges.

Be it further resolved, that NASUCA authorizes its Executive Committee to develop specific positions and take appropriate actions consistent with the terms of this resolution. The Executive Committee shall advise the membership of any proposed action prior to taking action if possible. In any event the Executive Committee shall notify the membership of any action pursuant to this resolution.

Submitted by Consumer Protection Committee
Approved June 28, 2011
San Antonio, Texas

[1] 2008 Individual State Report by the NARUC Consumer Affairs Subcommittee on Collections Data Gathering, NARUC Consumer Affairs Committee (Nov. 17, 2008), http://www.naruc.org/Publications/2008%20NARUC%20Collections%20Survey%20Report.pdf.

[2] Tracking the Home Energy Needs of Low-income Households Through Trend Data on Arrearages and Disconnections, National Energy Assistance Directors' Association (May 2004), available at http://www.neada.org/publications/TrackingtheNeed.pdf.

[3], Ron Grosse, Wisconsin Public Service Corporation, with Collaboration of Nancy Brockway, National Regulatory Research Institute (Revised 2008), available at http://nrri.org/pubs/multiutility/Win-WinAlternativesforCreditCollections.pdf.

[4] National Association of Regulatory Utility Commissioners, Resolution Supporting the Gathering of Data for Electric and Natural Gas Distribution Companies by Individual State Utility Commissions or Energy Offices (Nov. 14, 2007), available at http://www.naruc.org/resolutions.cfm.

EXHIBIT JH-11

Consolidated
Year: 2015
GAS PIPP REPORT

Enrollment Numbers for Active and Graduate PIPP Programs	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
(A) Number of Total Residential Customer Accounts												
(B) Number of Total PIPP Accounts												
1) Active, non-Grad PIPP												
a) New Enrollees												
b) Repeat Enrollees												
2) Graduate PIPP												
3) Percentage of Residential Customers on PIPP												
(C) Number of Customers Dropped from Active, Non-Grad PIPP Enrollment												
1) Non-payment												
2) Failure to reverify												
3) Failure to bring account current at anniversary date												
4) Income Ineligible												
5) Other												
(D)Number of Customers Dropped from Graduate PIPP Enrollment												
1) Non-payment												
2) Completed 12 month Graduate PIPP program												
a) Successfully Completed Graduate PIPP												
3) Failure to bring account current upon enrollment												
4) Other												
Billing & Payment Amounts for Active PIPP Customers												
(E) Total Billings for Active PIPP Accounts (based on usage)												
1) Average Total PIPP Bill												
(F) Total PIPP Payments Received												
1) Customer Payments												
2) E-HEAP payments												
3) HEAP payments												
(G)Unrecovered portion of Active PIPP Bills												
1) Percentage of total billings paid by Active PIPP Customers												
(H) PIPP Installment Billings												
1) Average PIPP Installment												
2) Percentage of Installment Billings Paid by Active Pipp Customers												
Payments Received and Incentive Credits Awarded												
(I) Number of PIPP installment payments received												
1) Active												
2) Graduate												
3) percentage of active PIPP installment payments received												
4) percentage of graduate PIPP installment payments received												
(J) Number of timely and full PIPP installment payments received												
1) Active												
2) Graduate												

3) percentage of active PIPP installments that are timely and in full												
4) percentage of graduate PIPP installments that are timely and in full												
(K) Total Dollars of on-time payment incentive credits awarded												
1) Active												
2) Graduate												
3) Average Active Credit												
4) Average Graduate Credit												
Usage												
(L) Average Monthly Mcf Usage of PIPP Customer												
(M) Average Monthly Mcf Usage of Non-PIPP Residential Customer												
Aged/Deferred Recoverable through PIPP Rider												
(N) Beginning Balance of Aged PIPP Arrearages												
(O) Aged/Deferred Current Month's PIPP Arrearages												
1) Number of months debt is held prior to aging												
2) Administrative costs (if applicable)												
3) Revenue sharing (if applicable)												
4) Carrying charges (if applicable)												
(P) Arrearage Recovery/PIPP Rider												
(Q) Ending Balance of PIPP Arrearages												
(R) Monthly volumes applicable to PIPP Rider /Mcf												
(S) Approved PIPP Rider Rate in Effect (Mcf)												

Consolidated Year: 2015 DISCONNECT-RECONNECT-DEPOSIT REPORT	JAN	FEB	MAR	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
A) Number of Non-PIPP Residential Customer Accounts										0	0	0
1) Number of Disconnections for non-payment										0	0	0
2) Number of Reconnections										0	0	0
3) Disconnection Rate										#DIV/0!	#DIV/0!	#DIV/0!
4) Ratio of Reconnections to Disconnections										#DIV/0!	#DIV/0!	#DIV/0!
B) Number of Non-PIPP Residential Customers on Payment Plans										0	0	0
1) Number of Disconnections for non-payment										0	0	0
2) Number of Reconnections										0	0	0
3) Disconnection Rate										#DIV/0!	#DIV/0!	#DIV/0!
4) Ratio of Reconnections to Disconnections										#DIV/0!	#DIV/0!	#DIV/0!
C) Number of Residential Customers on Active, Non-Grad PIPP										0	0	0
1) Number of Disconnections for non-payment										0	0	0
2) Number of Reconnections										0	0	0
3) Disconnection rate										#DIV/0!	#DIV/0!	#DIV/0!
4) Ratio of Reconnections to Disconnections										#DIV/0!	#DIV/0!	#DIV/0!
D) Number of Residential Customers on Graduate PIPP										0	0	0
1) Number of Disconnections for non-payment										0	0	0
2) Number of Reconnections										0	0	0
3) Disconnection Rate										#DIV/0!	#DIV/0!	#DIV/0!
4) Ratio of Reconnections to Disconnections										#DIV/0!	#DIV/0!	#DIV/0!
Length of Time Before Disconnection Occurred												
Non-PIPP Disconnections by Age of Default												
E) Number of Non-PIPP disconnections										0	0	0
1) Number with oldest defaulted amount equaling 90 days or less										0	0	0
2) Number with oldest defaulted amount between 91-180 days										0	0	0
3) Number with oldest defaulted amount equaling 181 days or more										0	0	0
4) % of oldest arrearages that are 90 days old or less										#DIV/0!	#DIV/0!	#DIV/0!
5) % of oldest arrearages between 91 and 180 days old										#DIV/0!	#DIV/0!	#DIV/0!
6) % of oldest arrearages that are 181 days old or more										#DIV/0!	#DIV/0!	#DIV/0!
PIPP (Active & Grad) Disconnections by Age of Default												
F) Number of PIPP and Grad PIPP disconnections										0	0	0
1) Number with oldest defaulted amount equaling 90 days or less										0	0	0
2) Number with oldest defaulted amount between 91-180 days										0	0	0
3) Number with oldest defaulted amount equaling 181 days or more										0	0	0
4) % of oldest arrearages that are 90 days old or less										#DIV/0!	#DIV/0!	#DIV/0!
5) % of oldest arrearages between 91 and 180 days old										#DIV/0!	#DIV/0!	#DIV/0!
6) % of oldest arrearages that are 181 days old or more										#DIV/0!	#DIV/0!	#DIV/0!
Customer Deposits												
G) Number of customer deposits assessed										0	0	0
H) Total dollar amount of all deposits assessed										$0	$0	$0
1) Average Deposit Amount										#DIV/0!	#DIV/0!	#DIV/0!
Length of Time Without Service at Reconnection												
I) Number of customers disconnected for 10 days or fewer										0	0	0
J) Number of customers disconnected for 11-30 days										0	0	0
K) Number of customers disconnected for 31-90 days										0	0	0
L) Number of customers disconnected for 91 days or more										0	0	0

Consolidated Year: 2015 EXTENDED PAYMENT PLAN SUCCESS & USE of MEDICAL CERTIFICATES REPORT	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
Extended Payment Plans												
(A) Number of Non-PIPP Residential Customers												
(B) Number of Customers on Extended Payment Plans												
1) One-third plan												
2) One-sixth plan												
3) One-ninth plan												
4) Budget payment plan												
5) Other plan												
6) % of customers on a payment plan												
7) % of all customers on 1/3 plan												
8) % of all customers on 1/6 plan												
9) % of all customers on 1/9 plan												
10) % of all customers on budget												
11) % of all customers on other plan												
12)Total Amount of Arrearages for customers on Extended Payment Plans												
Extended Payment Plans and Disconnections for Non-Payment												
(C) Number of residential customers disconnected for non-payment												
(D) Number of extended payment plan customers disconnected for non-payment												
1) One-third plan												
2) One-sixth plan												
3) One-ninth plan												
4) Other plan												
5) % of 1/3 plan customers disconnected												
6) % of 1/6 plan customers disconnected												
7) % of 1/9 plan customers disconnected												
8) % of customers on other plans disconnected												
Extended Payment Plans and Switching/Completion												
(E) Number of customers switching to an alternate payment plan												
1) Percentage of customers on a payment plan who switched to an alternate plan												
2) Switching off one-third												
3) Switching off one-sixth												
4) Switching off one-ninth												
5) Switching off other plan												
6) % switching off 1/3 plan												
7) % switching off 1/6 plan												
8) % switching off 1/9 plan												
9) % switching off other plan												
(F) Number of customers completing or meeting terms of a payment plan												
1) % of payment plan customers completing or meeting terms of payment plan												
2) Meeting terms of one-third plan												
3) Completing one-sixth plan												
4) Meeting terms one-ninth plan												
5) Completing other plan												
6) % meeting terms of 1/3 plan												
7) % completing 1/6 plan												
8) % meeting terms of 1/9 plan												
9) % completing other plan												
Medical Certification												

G) Number of all Residential Customers using medical certificates												
H) Number of PIPP Customers using medical certificates												
1) Active PIPP												
2) Graduate PIPP												

Consolidated Year: 2015 WINTER RECONNECT ORDER REPORT	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Customer Profile of WRO Use												
A) Number of Total Residential Customer Accounts												
B) Number of Total PIPP Accounts												
C) Number of non-PIPP Accounts												
D) Number of customers on extended payment plans												
E) Total number of residential customer accounts that used WRO												
1) % residential customers using WRO												
F) Number of PIPP customer accounts that used WRO												
1) % PIPP customers using WRO												
G) Number of non-PIPP customer accounts that used WRO												
1) % non-PIPP customers using WRO												
H) Number of non-PIPP customer accounts that used WRO and received E-HEAP												
I) Number of customers on extended payment plans that used WRO												
1) % of customers on extended payment plans that used WRO												
Reasons for WRO Use												
J) PIPP Customer Accounts that used WRO												
1) Avoid disconnection												
2) Re-establish service												
3) % used to avoid disconnection												
4) % used to re-establish service												
K) Non-PIPP Customer Accounts that used WRO												
1) Avoid Disconnection												
2) Re-establish service												
3) Establish service for a new customer												
4) % using to avoid disconnection												
5) % using to re-establish service												
Enrollment on PIPP or Extended Payment Plan Upon WRO Use												
L) Number of customers placed on extended payment plan within 30 days of invoking use of WRO												
M) Number of customers newly enrolled in PIPP within 30 days of invoking use of WRO												
Arrearage Balance Upon WRO Use												
N) Non-PIPP Only: The payment plan dollar amount entered into as a result of the WRO												
O) PIPP Only: The dollar amount added to PIPP Arrearage												
Length of Time Without Service Upon WRO Use												
P) Number of customers disconnected for 10 days or fewer												
Q) Number of customers disconnected for 11-30 days												
R) Number of customers disconnected for 31-90 days												
S) Number of customers disconnected for 91 days or more												

DATA DICTIONARY Submit data based on Revenue Month

MONTHLY GAS PIPP REPORT

Enrollment Numbers for Active and Graduate PIPP Programs

A) Number of total residential customer accounts: Report the number of active residential customer accounts. This number should be the same as what is reported in Line A of the Winter Reconnect Order Report.(#)

B) Number of Total PIPP accounts: This is the sum of B(1) + B(2), or the sum of active and Grad PIPP accounts. Does not include finaled or inactive accounts. This number should be the same as what is reported on Line B of the Winter Reconnect Order Report. (#)

1) Active, non-Grad PIPP: Report the number of active, non-Grad PIPP accounts. This should be the same as reported on Line C of the Disconnection-Reconnection Report. (#)

a. New enrollees: Report the number of customers who are new to PIPP, have not been enrolled within the previous 12 months, and who are active on PIPP at the end of the revenue month. (#)

b. Repeat enrollees: Report the number of PIPP enrollees who were on PIPP within the previous 12 months, dropped off, have now re-enrolled and are active on PIPP at the end of the revenue month. (#)

2) Graduate PIPP: Report the number of active Graduate PIPP accounts. This should be the same as Line D on the Disconnect Reconnect Report. (#)

*3) **Percentage of residential customers on PIPP:** Self-populates. Reports the percentage of residential customers who participate in PIPP, both active and graduate. (%) (Item B divided by item A)*

C) Total number of customers dropped from active PIPP enrollment: *Self-populates. C equals the total number of customer accounts that were dropped from active PIPP enrollment. C is the sum of C1 through C5. Includes only active PIPP customers. (#)*

1) Non-payment: Report the total number of Active PIPP customers that were dropped for non-payment during the revenue month. (#)

2) Failure to reverify: Report the total number of active PIPP customers dropped from enrollment for failure to reverify income within 60 days of the reverification date during the revenue month. (#)

3) Failure to bring account current at anniversary date: Report the total number of active PIPP customers dropped from enrollment for failure to make up missed PIPP payments within 30 days of anniversary date during the revenue month.(#)

4) Income ineligible: Report the total number of active PIPP customers dropped from enrollment due to income ineligibility during the revenue month. (#)
5) Other: Report the total number of customers who were dropped from the Active PIPP for any reason, other than C (1) thru C (4) during the revenue month. (#)
D) Total number of customers dropped from graduate PIPP enrollment: *Self-populates. D equals the total number of customer accounts that were dropped from graduate PIPP enrollment. D is the sum of D1 through D4. (#)*
1) Non-payment: Report the total number of Grad PIPP customers that were dropped for non-payment during the revenue month. (#)
2) Completed 12 month graduate PIPP program : Report the total number of customers who were dropped from Grad PIPP after 12 months, but continue to have an accrued arrearage. (#)
a. Successfully completed graduate PIPP: Report the number of customers who successfully completed grad PIPP during the revenue month. (#)
3) Failure to bring account current upon enrollment: Report the total number of customers enrolled on Grad PIPP who were dropped for failure to bring their PIPP account current within the 30 day grace period during the revenue month. (#)
4) Other: Total Number of customers who were dropped from the Grad PIPP program for any reason, other than D (1) -(3) during the revenue month. (#)
Billing & Payment Amounts for Active PIPP Customers
E) Total Billings for Active PIPP Accounts (based on usage): Report the total dollar amount of the current bills for Active PIPP customers. Do not report on billings for Grad PIPP customers.($)
1) Average Total PIPP Bill: *Self-populates. Reflects total billings for active PIPP customers ($) divided by the number of active PIPP customers. It is reflective of the average total bill received by an active PIPP customer. (#) E dividied by B (1).*
F) Total PIPP payments received: *Self-populates. This category reflects the total dollar value of payments made by active PIPP customers or payments made on behalf of active PIPP customers. ($) Sum of F (1) through F (3).*
1) Customer payments: Report the cumulative dollar amount of payments received directly from active PIPP customers. It includes payments by agencies (other than ODOD) on behalf of the customers. ($)
2) E-HEAP payments: Report the dollar amount of payments received via E-HEAP. ($)

3) HEAP payments: Report the dollar amount of payments received via HEAP. ($)

G) Unrecovered portion of Active PIPP bill: *Self-populates. Reflects PIPP Billings minus PIPP payments. ($) E minus F.*

*1) **Percentage of total billings paid by Active PIPP customers:** Self-populates. This shows what percent of total billings were paid. (%) F divided by E.*

H) PIPP Installments Billings: Report the cumulative total dollar amount of installment billings for active PIPP customers. ($)

1) Average PIPP installment: Self-populates. This is the average PIPP installment amount. ($) H divided by (B) 1

2) Percentage of Installment Billings Paid by Active PIPP Customers: Self populates. This is the amount of installment payments received divided by the amount of installment payments billed for active customers. (%) F (1) divided by H

Payments Received and Incentive Credits Awarded

I) Number of PIPP installment payments received: *Self-populates. Reflects the number of individual payments received from active and graduate PIPP customers. (#) Sum of I (1) and I (2)*

1) Active: Report the number of installment payments received from active PIPP customers. If customer makes multiple payments to cover one PIPP installment, count as one PIPP installment. (#) In the WRO months, this count will not include customers using the WRO that month.

2) Graduate: Report the number of installment payments received from graduate PIPP customers. (#)

3) Percentage of active PIPP installment payments received: Self-populates. This is number of active PIPP installments received divided by all active PIPP installments billed. (%) I (1) divided by B (1).

4) Percentage of Grad PIPP installment payments received: Self-populates. This is the number of grad PIPP installments received divided by all grad PIPP installments sent. (%)I (2) divided by B (2)

J) Number of timely and full PIPP installment payments received: Self-populates. This is the sum of active and graduate installment payments received that are timely and full. Sum of J (1) and J (2) (#)

1) Active: Report the number of timely and full installment payments received from active PIPP customers. (#)

2) Graduate: Report the number of timely and full installment payments received from Grad PIPP customers. (#)
3) Percentage of active PIPP installments that are timely and in full: Self-populates. This is timely and full active PIPP installments received divided by all active PIPP installments received. J (1) divided by I (1) (%)
4) Percentage of Grad PIPP installments that are timely and in full: Self-populates. This is timely and full Grad PIPP installments received divided by all grad PIPP installments received. J (2) divided by I (2) (%)
K) Total dollars of on-time payment incentive credits awarded: Self-populates. This is the sum of active and graduate dollars or K1 plus K2. It is the cumulative total dollar amount of payment incentive/arrearage forgiveness awarded. This is the amount of debt/arrearage forgiven due to on-time, full installment payments. It includes amounts forgiven towards arrearages as well as the portion of bills not covered by installment amounts. ($)
1) Active: Report the total dollar amount of incentive credits/arrearage forgiveness awarded to active PIPP customers. ($)
2) Graduate: Report the total dollar amount of incentive credits/arrearage forgiveness awarded to Grad PIPP customers. ($)
3) Average active credit: Self-populates. This is the total dollars awarded to active PIPP customers divided by the number of timely and full installment payments made by active PIPP customers. K (1) divided by J (1) ($)
4) Average graduate credit: Self-populates. This is the total of credits awarded to Grad PIPP customers divided by the total number of timely and full installment payments received from Grad PIPP customers. K (2) divided by J (2) ($)
Usage
L) Average monthly Mcf usage of PIPP customer: Report the average usage by PIPP customers, both active and graduate, by Mcf. (#)
M) Average monthly Mcf usage of non-PIPP residential customer: Report the usage of the average non-PIPP residential customer, by Mcf. (#)
Aged/Deferred Recoverable through PIPP rider
N) Beginning balance of aged PIPP arrearages: Report the balance of aged PIPP arrearages at the end of the revenue month. This should be the same as Q from the previous month's report. ($)
O) Aged/Deferred current month's PIPP arrearage: Report the balance of aged PIPP arrearages at the end of the revenue month. ($)

1) Number of months held prior to aging: Report the number of months your company keeps unpaid billings before sending them for recovery through the PIPP rider. (#)

2) Administrative Costs (if applicable): Report the amount of fees paid to ODOD for administration of PIPP, if applicable. ($)

3) Revenue Sharing (if applicable): Report the amount of dollars going to reduce the month's PIP arrearages located in (O). This should be reflected as a negative amount. Only populate if applicable to your company. (-$)

4) Carrying charges (if applicable): Report the amount of carrying charges on deferred PIPP balances that goes to increase the current month's PIPP arrearages. Report only if applicable to your company. ($)

P) Arrearage recovery/PIPP rider: Report the amount of recovery your company billed for the revenue month through the PIPP rider. ($)

Q) Ending balance of PIPP arrearages: Report the ending balance of PIPP arrearages at the end of the revenue month. Notwithstanding certain exceptions, this should be calculated as the beginning balance, plus the aged/deferred current month's PIPP arrearage, minus the arrearage recovery/PIPP rider. (N + O - P = Q) ($)

R) Monthly volumes applicable to PIPP rider/Mcf: Report the monthly volumes applicable to the PIPP rider, by Mcf. (#)

S) Approved PIPP rider rate in effect: Report the approved PIPP rider in effect at the end of the revenue month. Staff recognizes that R X S may not = P. ($)

DISCONNECTION for NON-PAYMENT / RECONNECTION / DEPOSIT REPORT

A) Number of Non-PIPP Residential Customer Accounts: Report number of residential accounts (excluding PIPP and grad PIPP). This should be the same as reported on Line A of the Payment Plan Success Report.(#)

1) Number of disconnections for non-payment: Report the number of disconnections for non-payment to non-PIPP, residential accounts.(#)

2) Number of reconnections: Report the number of reconnections to non-PIPP, residential accounts. A reconnection is any residential account that was terminated for non-payment and subsequently restored after meeting the utility's terms for restoration. (#)

3) Disconnection rate: Self populates. This is the % of all customers disconnected for non- payment during the revenue month.(%) A (1) divided by A

4) Ratio of reconnections to disconnections: Self populates. This is the ratio that shows the % of disconnected customers who reconnected during the revenue month. (%) A (2) divided by A (1)

B) Number of Non-PIPP Customers on Payment Plans: Report total number of residential customers on payment plans (excluding PIPP). (#)
1) Number of disconnections for non-payment: Report total number of customers who were on a payment plan within two previous billing cycles of dicsonnection for non-payment. (#)
2) Number of reconnections: Report number of customers that were reconnected during the revenue month. (#)
3) Disconnection rate: Self populates. This is the % of customers on payment plans disconnected during the revenue month.(%) B (1) divided by B
4) Ratio of reconnections to disconnections: Self populates. This is the ratio that shows the % of disconnected customers (on payment plans) who reconnected during the revenue month. (%) B (2) divided by B (1)
C) Number of Customers on Active, Non-Grad PIPP: Report total number of active, non-Grad PIPP accounts. This should be the same as reported on Line B(1) of the Gas PIPP Report.(#)
1) Number of disconnections for non-payment: Report total number of active PIPP (non-Grad) customer accounts disconnected for non-payment. (#)
2) Number of reconnections: Report number of customers that were reconnected during the revenue month. (#)
3) Disconnection rate: Self populates. This is the % of active, non-Grad PIPP customers disconnected during the revenue month.(%) C (1) divided by C
4)Ratio of reconnections to disconnections: Self populates. This is the ratio that shows the % of active, non-Grad, disconnected PIPP customers who reconnected during the revenue month. (%) C (2) divided by C (1)
D) Number of Customers on Graduate PIPP: Report total number of Graduate PIPP customer accounts. This should be the same as reported on Line B(2) of the Gas PIPP Report. (#)
1) Number of disconnections for non-payment: Report total number of Graduate PIPP customer accounts disconnected for non-payment. (#)
2) Number of reconnections: Report number of customers that were reconnected during the revenue month. (#)
3) Disconnection rate: Self-populates. This is the % of Grad PIPP customers disconnected during the revenue month. (%) D (1) divided by (D)

4)Ratio of reconnection to disconnections: Self-populates. This is the ratio that shows the % of disconnected Grad PIPP customers to those Grad PIPP customers who reconnected during the revenue month. (%) D (2) divided by D (1)
Length of Time Before Disconnection for Non-Payment Occurred
Non-PIPP disconnections for non-payment by age of default
E) Number of Non-PIPP disconnections: Report the number of non-PIPP accounts that defaulted and were disconnected. (#)
1) Number with the oldest defaulted amount equaling 90 days or less: Report the number of non-PIPP disconnections where the oldest defaulted amount was 90 days old or less. (#)
2) Number with the oldest defaulted amount between 91 and 180 days old: Report the number of non-PIPP disconnections where the oldest defaulted amount was between 91 and 180 days old. (#)
3) Number with oldest defaulted amount equaling 181 days or more: Report the number of non-PIPP disconnections where the oldest default amount was 181 days old or more. (#)
4)% of oldest arrearages that are 90 days old or less: Self-populates. Reports the % of non-PIPP customers whose oldest debt was 90 days old or less (%) I (1) divided by I
5) % of oldest arrearages between 91 and 180 days old: Self-populates. Reports the % of non-PIPP customers disconnected whose oldest debt was between 91 and 180 days old. (%) I (2) divided by I
6)% of oldest arrearages that are 181 days old or more : Self populates. Reports the % of non-PIPP customers disconnected whose oldest debt was 181 days old or more (%) I (3) divided by I
PIPP (Active and Grad) disconnections for non-payment by age of default
F) Number of PIPP and Grad PIPP disconnections: Report the number of PIPP and Grad PIPP accounts that defaulted and were disconnected. (#)
1) Number with oldest defaulted amount 90 days or less: Report the number of PIPP accounts that were disconnected where the the oldest debt was 90 days old or less. (#)
2) Number with oldest defaulted amount between 91 and 180 days old: Report the number of PIPP disconnections where the oldest defaulted amount was between 91 and 180 days old. (#)

3) Number with oldest defaulted amount equaling 181 days or more: Report number of PIPP accounts disconnected where oldest defaulted amount was outstanding 181 or more. (#)
4) % of oldest arrearages that are 90 days old or less: Self populates. Reports the % of PIPP customers disconnected whose oldest debt was 90 days old or less (%) J (1) divided by J
5) % of oldest arrearages between 91 and 180 days old: Self-populates. Reports the % of PIPP customers disconnected whose oldest debt was between 91 and 180 days old. (%) J (2) divided by J
6) % of oldest arrearages that are 181 days old or more: Self populates. Reports the % of PIPP customers disconnected whose oldest debt was 181 days old or more (%) J (3) divided by J
Customer Deposits
G) Number of customer deposits assessed: Report the number of customers assessed a deposit during the revenue month. (#)
H) Total dollar amount of all deposits assessed: Report the total dollar amount of all the deposits assessed during the revenue month. If the deposit is being billed in installments, only report the full deposit amount one time, during the revenue month that it is assessed. ($)
1) Average Deposit Amount: *Self populates: This is the average deposit amount. H divided by G.*
Length of Time Without Service at Reconnection
I) Number of customers disconnected for 10 days or fewer: Report the number of customers who were disconnected for 10 days or fewer. (#)
J) Number of customers disconnected for 11-30 days: Report the number of customers who were disconnected for 11-30 days. (#)
K) Number of customers disconnected for 31-90 days: Report the number of customers who were disconnected for 31-90 days. (#)
L) Number of customers disconnected for 91 days or more: Report the number who were disconnected for 91 days or more. (#)
EXTENDED PAYMENT PLAN SUCCESS & USE OF MEDICAL CERTIFICATES REPORT

Extended Payment Plans
A) Number of Non-PIPP residential customers: Report the number of residential accounts (excluding PIPP and Grad PIPP). This should be the same as reported on Line A of the Disconnect-Reconnect Report. (#)
B) Number of customers on payment plans: Self-populates. *Reports the total number of accounts on the 1/3, 1/6, 1/9, or other utility agreed upon payment plan (excludes PIPP accounts). Based on number of residential accounts on payment plans on the last day of revenue month. Should be the same as Line D of the Winter Reconnect Order, during applicable months. (#) Sum of B (1) through B (5)*
1) 1/3 plan: Report, based on the last day of the revenue month, the total number of accounts currently on the 1/3 payment plan. (#)
2) 1/6 plan: Report, based on the last day of the revenue month, the total number of accounts currently on the 1/6 payment plan. (#)
3) 1/9 plan: Report, based on the last day of the revenue month, the total number of accounts currently on the 1/9 payment plan. (#)
4) Budget plan: Report, based on the last day of the revenue month, the total number accounts currently on the budget payment plan. (#)
5) Other plan: Report, based on the last day of the revenue month, the total number of accounts currently on a utility agreed upon payment plan (do not include payment date extensions). (#)
6) % of customers on a payment plan: *Self populates. Of all residential customers, this is the % who are a payment plan. (%) B divided by A*
7) % of all customers on 1/3 plan: *Self populates. Of all customers on a payment plan, this is the % on the 1/3 plan. (%) B (1) divided by B*
8) % of all customers on 1/6 plan: *Self populates. Of all customers on a payment plan, this is the % on the 1/6 plan. (%) B(2) divided by B*
9) % of all customers on 1/9 plan: *Self populates. Of all customers on a payment plan, this is the % on the 1/9 plan. (%) B (3) divided by B*
10) % of all customers on budget plan: *Self populates. Of all customers on a payment plan, this is the % on the budget plan. (%) B (4) divided by B*
11) % of all customers on other plan: *Self populates. Of all customers on a payment plan, this is the % of customers on a plan other than 1/3, 1/6, 1/9, or budget. (%) B (5) divided by B*

12)Total Amount of Arrearages for customers on Extended Payment Plans: Report, based on the last day of the revenue month, the total amount of payment plan arrearages (do not include accounts with a payment date extension). ($)
Extended Payment Plans and Disconnections for Non-Payment
C) Number of residential customers disconnected for non-payment: Report total number of residential accounts disconnected for non-payment during the revenue month (#).
D) Number of extended payment plan customers disconnected for non-payment: *Self-populates. Of the total number disconnected, number of residential accounts on payment plans prior to (within two billing cycles) disconnection . (exclude PIPP and Graduate PIPP.) Sum of D1-4. (#)*
1) 1/3 plan: Of the total number disconnected, report number of residential accounts on 1/3 payment plan prior to (within two billing cycles) disconnection. Use number disconnected during the revenue month. (#)
2) 1/6 plan: Of the total number disconnected, report number of residential accounts on 1/6 payment plan prior to (within two billing cycles) disconnection. Use number disconnected during the revenue month. (#)
3) 1/9 plan: Of the total number disconnected, report number of residential accounts on 1/9 payment plan prior to (within two billing cycles) disconnection. Use number disconnected during the revenue month. (#)
4) Other plan: Of the total number disconnected, report number of residential accounts on a payment plan other than the 1/3, 1/6 or 1/9 prior to disconnection (within two billing cycles). Use number disconnected during the revenue month. (#)
5) % of 1/3 plan customers disconnected: *Self populates. Of all customers on a payment plan at the time of disconnection this is the % who were on the 1/3 plan. (%) D (1) divided by D*
6) % of 1/6 plan customers disconnected: *Self populates. Of all customers on a payment plan at the time of disconnection this is the % who were on a 1/6 plan. (%) D (2) divided by D*
7) % of 1/9 plan customers disconnected: *Self populates. Of all customers on a payment plan at the time of disconnection this is the % who were on a 1/9 plan. (%) D (3) divided by D*
8) % of customers on other plan disconnected: *Self populates. Of all customers on a payment plan at the time of disconnection this is the % of customers on a plan other than the 1/3, 1/6 or 1/9 plans. (%) D (4) divided by D*
Extended Payment Plans and Switching/Completion / Switching = Customers changing plans within the revenue month
E) Number of customers switching to an alternate payment plan: Report total number of customer who switched from one payment plan to another payment plan. Use the number of customers switching to an alternate plan during the revenue month. (#)

1) Percentage of customers on a payment plan who switched to an alternate plan: *Self populates. This is the % of customers who switched plans. (%) E divided by B*
2) Switching off 1/3: Report number of customers on 1/3 plan who switched to another payment plan. (#)
3) Switching off 1/6: Report number of customers on 1/6 plan who switched to another payment plan. (#)
4) Switching off 1/9: Report number of customers on 1/9 plan who switched to another payment plan. (#)
5) Switching off other plan: Report number of customers on utility agreed upon payment plan who switched to another plan. (#)
6) % switching off 1/3 plan: *Self populates. This is the % of customers on 1/3 plan who switched to another plan. (%) E (2) divided by E*
7) % switching off 1/6 plan: *Self populates. This is the % of customers on 1/6 plan who switched to another plan. (%) E (3) divided by E*
8) % switching off 1/9 plan: *Self populates. This is the % of customers on 1/9 plan who switched to another plan. (%) E (4) divided by E*
9) % switching off other plan: *Self populates. This is the % of customers on a utility agreed upon plan who switched to another plan. (%) E (5) divided by E*
F) Number of customers completing or meeting terms of payment plan: *Self populates. This is the total number of customers who completed or met the terms of a payment plan. (#) Sum of F(2) through F (5)*
1) Percentage of payment plan customers completing or meeting terms of payment plan: *Self populates. This is the % of customers who completed or met the terms of a payment plan. (%) F divided by B*
2) Meeting terms of 1/3: Report number of customers who met terms of 1/3 plan throughout the Winter Heating Season (this should only be entered when the season ends.) (#)
3) Completing 1/6: Report number of customers who paid all required 1/6 payments to bring account current. (#)
4) Meeting terms of 1/9: Report number of customers who paid all required 1/9 payments to bring account current. (#)

5) Completing other plan: Report number of customers who paid all required payments to bring account current. (#)
6) % meeting terms of 1/3 plan: *Self populates. This is the % of customers on 1/3 plan who met terms of the plan. (%) F (2) divided by B (1)*
7) % completing 1/6 plan: *Self populates. This is the % of customers on 1/6 plan who completed the plan. (%) F (3) divided by B (2)*
8) % meeting terms 1/9 plan: *Self populates. This is the % of customers on 1/9 plan who met the terms of the plan. (%) F (4) divided by B (3)*
9) % completing other plan: *Self populates. This is the % of customers on a utility agreed upon plan who completed the plan. (%) F (5) divided by B (5)*
Medical Certification
G) Number of all residential customers using medical certificate: Report, based on the last day of the revenue month, number of medical certificates used by residential customers. (#)
H) Number of PIPP customers using medical certificate: *Self populates. This is the number of all PIPP customers using a medical certificate. (#) Sum of H (1) and H (2)*
1) Active PIPP: Report number of medical certificates used by Active PIPP customers. Use number of active med certs on the last day of the revenue month. (#)
2) Graduate PIPP: Report number of medical certificates used by Graduate or Post-PIPP customers. Use number of active med certs on the last day of the revenue month. (#)

WINTER RECONNECT ORDER REPORT

Customer Profile of WRO Use

A) Number of Total Residential Customer Accounts: Report each individually billed account under a unique residential account number and residential tariff rate. (Count the number of residential bills you issue.) This should be the same as line A of the Gas PIPP report. (#)

B) Number of Total PIPP Accounts: Report the number of total PIPP accounts, both active and graduate. This should be the same as Line B of the Gas PIPP Report. (#)

C) Number of non-PIPP Accounts: *Self-populates. This is the number of residential customer accounts minus the number of PIPP accounts. A-B=C.(#)*

D) Number of customers on extended payment plans: Report the number of customers on an extended payment plans (exclude PIPP accounts). This is based on the last day of reporting and should be the same as reported on Line B of the Payment Plan Success Report. (#)

E) Total number of residential customer accounts that used WRO: *Self-populates. Total of PIPP customers plus non-PIPP customers using the WRO. F+G=E. (#)*

1) % residential customers using WRO: *Self-populates. Out of all residential customer accounts, this is the % that used the WRO. (%)*

F) Number of PIPP customer accounts that used WRO: Report total number of PIPP customers (including repeat enrollees & Grad PIPP) who used the WRO. (#)

1) % PIPP customers using WRO: Self-populates. *Out of all PIPP customers, this is the % that used the WRO. (%)*

G) Number of non-PIPP customers accounts that used WRO: Report the total of non-PIPP customers who used the WRO. (#)

1) % non-PIPP customers using the WRO: *Self-populates. Out of all non-PIPP customers, this is the % who used the WRO. (%)*

H) Number of Non-PIPP customer accounts that used WRO and received E-HEAP: Report the number of customers who used the WRO and received the $175 EHEAP benefit. (#)

I) Number of customers on extended payment plans that used the WRO: Report the number of customers who were on the 1/3, 1/6 1/9 or other extended payment plan prior to using the WRO (within the revenue month). (#) (Some companies will report zero which remove customers from payment plans upon default.)

1) % of customers on extended payment plans that used the WRO: *Of all customers on extended payment plans, this is the % that used the WRO. This is D/I. (%)*
Reasons for WRO Use
J) PIPP Customer Accounts that used WRO: *Self populates. This is the total of PIPP customers who used the WRO. This is the same as (F) above. (#)*
1) Avoid disconnection: Report total number of PIPP customers who used the WRO to avoid disconnection. (#)
2) Re-establish service: Report total number of PIPP customers who used the WRO to re-establish service. (#)
3) % used to avoid disconnection: *Self-populates. Of all PIPP customers who used the WRO, this is the % who used it to avoid disconnection. (%)*
4) % used to re-establish service: *Self populates. Of all PIPP customers who used the WRO, this is the % who used it to re-establish service. (%)*
K) Non-PIPP Customer Accounts that used WRO: *Self populates. This is the total of non-PIPP customers who used the WRO. This is the same as (G), above. (#)*
1) Avoid disconnection: Report total number of non-PIPP customers who used the WRO to avoid disconnection. (#)
2) Re-establish service: Report total number of non-PIPP customers who used the WRO to re-establish service. (#)
3) Establish service: Report number of non-PIPP customers who used WRO to establish service. (#)
4) % Using to avoid disconnection: *Self populates. Of all non-PIPP customers using the WRO, this % used it to avoid disconnection. (%)*
5) % Using to re-establish service: *Self populates. Of all non-PIPP customers using the WRO, this % used it to re-establish service. (%)*
Enrollment on PIPP or Extended Payment Plan Upon WRO Use

L) Number of customers placed on extended payment plan within 30 days of invoking use of the WRO: Report number of customers placed on an extended payment plan within 30 days of invoking use of the WRO. (#)
M) Number of customers newly enrolled in PIPP within 30 days of invoking use of the WRO: Report number of customers newly enrolled in PIPP within 30 days of invoking use of the WRO. (#)
Arrearage Balance of WRO Use
N) Non-PIPP Only: The payment plan dollar amount entered into as a result of the WRO: Report the dollar amount non-PIPP customers owe after the $175 has been paid. This is the total amount due on the payment plan arrangements. ($)
O) PIPP Only: The dollar amount added to PIPP Arrearage: Report the total dollar amount outstanding after the $175 has been paid for PIPP customers. This is the total amount added to customers' PIPP arrearages. ($)
Length of Time Without Service Upon WRO Use
P) Number of customers disconnected for 10 days or less: Of the customers who used the WRO, report the number who were disconnected for 10 days or fewer. (#)
Q) Number of customers disconnected for 11-30 days: Of the customers who used the WRO, report the number of customers who were disconnected for 11-30 days. (#)
R) Number of customers disconnected for 31-90 days: Of the customers who used the WRO, report the number of customers who were disconnected for 31-90 days. (#)
S) Number of customers disconnected for 91 days or more: Of the customers who used the WRO, report the number who were disconnected for 91 days or more. (#)

EXHIBIT JH-12

Utility Name:______________________________________ Data for October 1 through January 31

REPORT I
(due February 20, 2015)

Former Residential Heat-Related Customers Disconnected for Non-Payment Prior to September 15th
(Please respond to every question, even if that response is "0".)

		# of Accounts	Amount Owed
1.	Accounts still off as of September 15.	______	______
2.	Number of former customers utility attempted to contact (letters mailed on or before October 1).	______	
3.	Number of former customers requesting connection (3 = 4+5)	______	______
4.	Number of former customers reconnected. (Cannot be more than Item #3.) **(# of Accounts = # of Accounts listed in 4a + 4b + 4c + 4d)**	______	______

		# of Accounts	Amount Paid
4a.	Number reconnected for full amount.	______	______
4b.	Number reconnected for 1/3 down payment.	______	______
4c.	Number reconnected for 1/5 down payment.	______	______
4d.	Number reconnected for other down payment.	______	______

Note: The sum of 4a, 4b, 4c and 4d "Amount Paid" column will not equal "Amount Owed" in Question 4.

	# of Accounts	Amount Owed
5. Number of former customers denied reconnection **(#5 = 5a + 5b + 5c + 5d)**.		

REASONS FOR DENIAL	# of Accounts	Amount Owed
5a. Number due to failure to pay 1/3 amount billed since December 1.		
5b. Number due to tampering.		
5c. Number due to failure to make required down payment.		
5d. Number due to reconnection previous year.		

6. Number of DPA's extending:	**# of DPAs**
4 months or less	
5 months	
6 months	
7 months	
8 months	
9 months or more	
TOTAL:	

Note: Total # of DPAs must equal sum of accounts for 4b, 4c and 4d.

7.	Number of reconnected accounts that had an outstanding balance prior to application of downpayment in the following ranges:	**# of Accounts**
	$ 0 - $100	____________
	$101 - $200	____________
	$201 - $400	____________
	$401 - $600	____________
	$601 - $800	____________
	$801 - $1000	____________
	$1001 or more	____________
		# of Deposits
8.	Number of deposits requested on reconnected accounts.	____________

<u>The responses to Questions 9-15 should relate to heat-related residential customers disconnected for non-pay on or after October 1 through January 31.</u>
Note: For October, only include customers with energy assistance applications. Then the regular moratorium period begins from November 1 to March 31 for all other customers.

		# of Accounts	Amount Owed
9.	Number of former customers reconnected. **(# of Accounts = # of accounts listed in 9a + 9b + 9c + 9d)**	______	______

		# of Accounts	Amount Paid
9a.	Number reconnected for full amount.	______	______
9b.	Number reconnected for 1/3 down payment.	______	______
9c.	Number reconnected for 1/5 down payment.	______	______
9d.	Number reconnected with other down payment.	______	______

Note: The sum of 9a, 9b, 9c and 9d "Amount Paid" will <u>not</u> equal "Amount Owed" in Question 9.

		# of Accounts	Amount Owed
10.	Number of former customers denied reconnection **(#10 = 10a + 10b + 10c + 10d)**	______	______

<u>REASON FOR DENIAL:</u>		# of Accounts	Amount Owed
10a.	Number due to failure to pay 1/3 amount billed since December 1.	______	______
10b.	Number due to tampering.	______	______
10c.	Number due to failure to make required down payment.	______	______
10d.	Number due to reconnection previous year.	______	______

11. Number of DPAs extending: **# of DPAs**

4 months or less	______
5 months	______
6 months	______
7 months	______
8 months	______
9 months or more	______
TOTAL	______

Note: Total # of DPAs must equal sum of accounts for 9b, 9c and 9d.

12. Number of reconnected accounts with an outstanding balance prior to the down payment in the following ranges:

	# of Accounts
$ 0 - $100	______
$101 - $200	______
$201 - $400	______
$401 - $600	______
$601 - $800	______
$801 - $1000	______
$1001 or more	______

13. Number of deposits requested on reconnected accounts. **# of Deposits** ______

14. Customers disconnected.

	# of Accounts	Amount Owed
October		
November		
December		
January		
February		
March		

15. Number of defaults on DPAs made under Section 280.138 (do not include those DPAs which are reinstated or renegotiated unless they are defaulted upon subsequent to the reinstatement/renegotiation.)

* The number of DPAs, defaults and default rate should be cumulative. (# of Defaults divided by # of DPAs = Default Rate %.)

	# DPAs	# of Defaults	Default Rate(%)
October			
November			
December			
January			
February			
March			

Utility Name:_____________________________________ Data for October 1 through March 31

REPORT II
(due May 20, 2015)

<u>Former Residential Heat-Related Customers Disconnected for Non-Payment Prior to September 15th</u>
(Please respond to every question, even if that response is "0".)

		# of Accounts	Amount Owed
1.	Accounts still off as of September 15.	________	________
2.	Number of former customers utility attempted to contact (letters mailed on or before October 1).	________	
3.	Number of former customers requesting connection (3 = 4+5)	________	________
4.	Number of former customers reconnected. (Cannot be more than Item #3.) **(# of Accounts = # of Accounts listed in 4a + 4b + 4c + 4d)**	________	________

		# of Accounts	Amount Paid
4a.	Number reconnected for full amount.	________	________
4b.	Number reconnected for 1/3 down payment.	________	________
4c.	Number reconnected for 1/5 down payment.	________	________
4d.	Number reconnected for other down payment.	________	________

Note: The sum of 4a, 4b, 4c and 4d "Amount Paid" column will not equal "Amount Owed" in Question 4.

	# of Accounts	Amount Owed
5. Number of former customers denied reconnection **(#5 = 5a + 5b + 5c + 5d)**.		

REASONS FOR DENIAL	# of Accounts	Amount Owed
5a. Number due to failure to pay 1/3 amount billed since December 1.		
5b. Number due to tampering.		
5c. Number due to failure to make required down payment.		
5d. Number due to reconnection previous year.		

6. Number of DPA's extending:	**# of DPAs**
4 months or less	
5 months	
6 months	
7 months	
8 months	
9 months or more	
TOTAL:	

Note: Total # of DPAs must equal sum of accounts for 4b, 4c and 4d.

7. Number of reconnected accounts that had an outstanding balance prior to application of downpayment in the following ranges:

Range	**# of Accounts**
$ 0 - $100	______________
$101 - $200	______________
$201 - $400	______________
$401 - $600	______________
$601 - $800	______________
$801 - $1000	______________
$1001 or more	______________

# of Deposits

8. Number of deposits requested on reconnected accounts. ______________

<u>The responses to Questions 9-15 should relate to heat-related residential customers disconnected for non-pay on or after October 1 through March 31.</u>
Note: For October, only include customers with energy assistance applications. Then the regular moratorium period begins from November 1 to March 31 for all other customers.

		# of Accounts	Amount Owed
9.	Number of former customers reconnected. **(# of Accounts = # of accounts listed in 9a + 9b + 9c + 9d)**	______	______

		# of Accounts	Amount Paid
9a.	Number reconnected for full amount.	______	______
9b.	Number reconnected for 1/3 down payment.	______	______
9c.	Number reconnected for 1/5 down payment.	______	______
9d.	Number reconnected with other down payment.	______	______

Note: The sum of 9a, 9b, 9c and 9d "Amount Paid" will <u>not</u> equal "Amount Owed" in Question 9.

		# of Accounts	Amount Owed
10.	Number of former customers denied reconnection **(#10 = 10a + 10b + 10c + 10d)**	______	______

<u>REASON FOR DENIAL:</u>		# of Accounts	Amount Owed
10a.	Number due to failure to pay 1/3 amount billed since December 1.	______	______
10b.	Number due to tampering.	______	______
10c.	Number due to failure to make required down payment.	______	______

10d. Number due to reconnection previous year. ____________ | ____________

11. Number of DPAs extending: **# of DPAs**

	# of DPAs
4 months or less	______
5 months	______
6 months	______
7 months	______
8 months	______
9 months or more	______
TOTAL	______

Note: Total # of DPAs must equal sum of accounts for 9b, 9c and 9d.

12. Number of reconnected accounts with an outstanding balance prior to the down payment in the following ranges:

	# of Accounts
$ 0 - $100	______
$101 - $200	______
$201 - $400	______
$401 - $600	______
$601 - $800	______
$801 - $1000	______
$1001 or more	______

# of Deposits

13. Number of deposits requested on reconnected accounts. ______

14. Customers disconnected.

	# of Accounts	Amount Owed
October		
November		
December		
January		
February		
March		

15. Number of defaults on DPAs made under Section 280.138 (do not include those DPAs which are reinstated or renegotiated unless they are defaulted upon subsequent to the reinstatement/renegotiation.)

* The number of DPAs, defaults and default rate should be cumulative. (# of Defaults divided by # of DPAs = Default Rate %.)

	# DPAs	# of Defaults	Default Rate(%)
October			
November			
December			
January			
February			
March			

EXHIBIT JH-13

Report on 2013 Universal Service Programs & Collections Performance

of the Pennsylvania Electric Distribution Companies & Natural Gas Distribution Companies

Pennsylvania Public Utility Commission
Bureau of Consumer Services

Table of Contents

1. Introduction

The Pennsylvania Public Utility Commission's (PUC) Annual Report on 2013 Universal Service Programs and Collections Performance of the Pennsylvania electric distribution companies (EDCs) and natural gas distribution companies (NGDCs) includes data and performance measures for the seven major EDCs and the eight major natural gas NGDCs.

The Electricity Generation Customer Choice and Competition Act[1] and the Natural Gas Choice and Competition Act[2] opened the electric generation and natural gas supply markets to competition. In doing so, the General Assembly wanted to ensure that electric and natural gas service remain universally available to all customers in the state. Consequently, both Acts contain provisions relating to universal electric and gas service.

Specifically, both Acts require the Commission to maintain, at a minimum, the protections, policies, and services that assist customers who are low-income to afford electric and gas service.[3] The Acts also require the Commission to ensure that universal service and energy conservation policies are appropriately funded and available in each electric and natural gas distribution territory[4]. To assist the Commission in fulfilling its universal service obligations, the Commission established standard reporting requirements for universal service and energy conservation for both the EDCs and the NGDCs[5].

The Universal Service and Energy Conservation Reporting Requirements[6] (USRR) became effective Aug. 8, 1998, for EDCs and Dec. 16, 2000, for NGDCs. This data assists the Commission in monitoring the progress of the EDCs and NGDCs in achieving universal service in their respective service territories. The utilities covered by these reporting requirements are Duquesne Light, FirstEnergy companies – Metropolitan Edison, Pennsylvania Electric, PennPower and West Penn Power (formerlly Allegheny Power), PECO-Electric, PPL, Columbia, Equitable, NFG, PECO-Gas, Peoples (formerly Dominion Peoples), PGW, UGI Penn Natural, and UGI-Gas.

Each year, the EDCs and NGDCs report the previous year's data on April 1. The PUC then conducts a data-cleaning and error-checking process, including both written and verbal dialogue between the PUC and companies. Uniformity issues are documented in various tables, charts and appendices and also are discussed in more detail in later chapters. The PUC continues to work with the companies to obtain uniform data that fully complies with the regulations.

Universal Service Programs

LIURP — The Low Income Usage Reduction Program (LIURP) is an energy conservation and education program. Qualifying households receive an energy audit to assess household condition and energy usage; free installation of energy conservation and energy efficiency measures such as insulation, air sealing, and appliance installation if cost effective; and, free education on energy conservation and usage reduction.

CAP — Customer Assistance Program (CAPs) are payment assistance and debt forgiveness programs for payment-troubled households. CAPs are intended to provide affordable monthly bills based on a set energy burden standard. These lower rates are applied to ongoing usage as long as the household remains current and timely paying its monthly customer assistance payments. CAP rates may take the form of a discounted price on actual usage on either all or a portion of the usage, a percentage of the monthly bill, or a monthly amount that is calculated upon a percentage of the household income. Percentage of income plans are correlated directly to the household's income

[1] 66 Pa. C.S. §§ 2801-2812
[2] 66 Pa. C.S. Chapter 22
[3] 66 Pa. C.S. §§ 2203(7), §§ 2802(10)
[4] 66 Pa. C.S. §§ 2203(8), §§ 2804(9)
[5] 52 Pa. Code §§ 54.71–54.78, §§ 62.1-62.8
[6] 52 Pa. Code § 54.75(2)(ii)(C)(III) for EDCs and 52 Pa. Code § 62.5 (2)(ii)(C)(III) for NGDCs

and the Commission-determined allowable energy burden percentage. CAP's debt forgiveness feature freezes a household's unpaid past debt upon entry into the program. As long as the household remains current and timely on their future payments, the past debt is not collected upon and is eventually forgiven in incremental amounts over time.

CARES — Customer Assistance and Referral Evaluation Services (CARES) is a social service and referral program for households encountering some form of extenuating circumstance or emergency that results in the household's inability to pay for utility service. Qualifying households may receive counseling and/or direct referrals to community resources that can aid the family in resolving the emergency.

Hardship Fund — Hardship funds are programs that make cash grants available to qualifying households, to assist in the payment of outstanding debt owed by the household to the utility company. They are funded through contributions made by the public that are matched by the company and paid directly to the utility.

Treatment of PECO Data

PECO serves three types of customers: those who receive only electric service (electric only); those who receive both electric and gas service (combination/electric and gas); and, those who receive only gas service (gas only). PECO also reports the electric and gas data separately. In order to split the second group (combination/electric and gas) for some of the data variables, PECO used an allocation factor consistent with PECO's gas base rate filing of March 31, 2008. The allocation factor for 2013 splits the combination group into 87 percent electric and 13 percent gas. However, for other data variables, PECO did not apply the allocation method. Instead, PECO includes the combination group in both the electric and gas totals.

Treatment of the FirstEnergy Companies

Beginning with 2003 data, FirstEnergy Corp. requested permission to identify and report separately on the FirstEnergy companies that provide utility service in Pennsylvania. Therefore, this report shows universal service data for the three FirstEnergy companies: Metropolitan Edison (Met-Ed), Pennsylvania Electric (Penelec), and Penn Power. Also, on Feb. 24, 2011, the PUC approved the FirstEnergy aquisition of Allegheny Power. Starting with the 2011 report, we identify the company as West Penn Power.

Treatment of Confirmed Low-Income Data Among the Collections Performance Data

We have included data about confirmed low-income customers in Chapter 1 for only a select number of collections performance measures. The majority of the confirmed low-income collection data tables appear as a grouping of tables in Appendix 1. Also included in this grouping of tables in Appendix 1 is a presentation of company revenues or billings.

Responsible Utility Customer Protection Act Act 201 of 2004[7] changed the rules that apply to cash deposits, reconnection of service, termination of service, payment agreements, and the filing of termination complaints by consumers for electric, gas, and water. The goal was to increase timely collections while ensuring that service is available to all customers based on equitable terms and conditions.[8] The law is applicable to EDCs, water distribution companies, and NGDCs with an annual operating income in excess of $6,000,000.[9] Steam and wastewater utilities are not covered by Chapter 14. The Commission amended Chapter 56 to make these regulations consistent with Chapter 14[10]. Every two years, the Commission reports to the General Assembly on the effectiveness of the Act[11]. .

---

[7] 66 Pa.C.S. §§1401-1418
[8] 66 Pa. C.S. §1402
[9] Small natural gas companies may voluntarily "opt in" to Chapter 14. 66 Pa. C.S. §1403.
[10] Docket no. L-00060182, published in Pennsylvania Bulletin Oct. 8, 2011.
[11] Chapter 14 was renewed on Oct.22, 2014. for 10 years. The next Report is due in five years.

CAP Rulemaking and Policy Statement

As the result of an investigation into CAP funding levels and cost recovery mechanisms[12], the Commission began the process to revise its policy statement[13] and regulations[14] regarding CAPs. In May 2012, the Commission discontinued the rulemaking and the proposed revisions to the CAP policy statement[15] due to developments that occurred since the initiation of these two proceedings. The developments included changes to the application of Low Income Home Energy Assistance Program (LIHEAP) funds in a distribution company's CAP. In addition, stakeholders are studying the treatment of universal service customers in an enhanced competitive retail electricity market and this subgroup may recommend regulatory changes or revisions to the CAP policy statement. The Commission indicated that a new rulemaking and amended policy statement may be initiated in the future.

On April 9, 2010, the PUC suspended portions[16] of the CAP policy statement regarding the application of LIHEAP grants to a distribution company's CAP because the sections were inconsistent with the state Department of Public Welfare's changes to its administration of LIHEAP.[17] The suspension of Sections 69.265(9)(ii-iii) of the Commission's regulations is still in effect.

Equitable-Peoples Merger

On December 18, 2013, Equitable Gas Company was merged into Peoples Natural Gas Company LLC ("Peoples"). The 2013 Universal Services Report reflects separate data for Peoples and Equitable.

[12] Final Order entered Dec. 18, 2006 at docket no. M-00051923

[13] 52 Pa. Code §§ 69.261-69.267. Policy statement proposal docket no. M-00072036.

[14] 52 Pa. Code § 54.74 and § 62.4. Proposed rulemaking docket no. L-00070186.

[15] Docket Nos. L-00070186 (Rulemaking) and M-00072036 (Policy Statement)

[16] 52 Pa. Code §§ 69.265(9)(ii-iii)

[17] Set forth in DPW's 2010 Final State Plan

2. Collection Performance

The regulations require EDCs and NGDCs to report various residential collection data. The following report content reviews each of the collection measures by presenting the raw data itself and by using the data to arrive at calculated variables that are more useful in analyzing collection performance. All of the data and statistics used in this chapter are drawn from information submitted by the companies.

It is also important to note that we have reflected both the number of confirmed low-income customers and the number of estimated low-income customers in a utility's given service territory. A low-income customer is defined as one whose household income is at or below 150 percent of the federal poverty income guidelines (FPIG)[18]. A confirmed low-income customer is a customer whose gross household income has been verified as meeting the FPIG. Most household incomes are verified through the customer's receipt of a LIHEAP grant or determined during the course of making a payment agreement. The estimated low-income customers represent the company's approximation of its total universe of low-income customers.

Number of Residential Customers

The number of residential customers represents an average of the 12 months of month-end data reported by the companies. The data includes all residential customers, including universal service program recipients.

Number of Residential Electric Customers

Company	Number of Residential Customers
Duquesne	526,817
Met-Ed	488,375
PECO-Electric	1,421,426
Penelec	504,543
Penn Power	141,147
PPL	1,218,734
West Penn	619,531
Total	**4,920,573**

Number of Residential Natural Gas Customers

Company	Number of Residential Customers
Columbia	384,213
Peoples	330,123
Peoples-Equitable	242,632
NFG	198,763
PECO-Gas	456,331
PGW	468,943
UGI-Gas	324,576
UGI Penn Natural	149,097
Total	**2,554,678**

[18] See Appendix 4

*Number of Confirmed Low-Income Electric Customers**

Company	Number of Confirmed Low-Income Customers	Percent of Customers
Duquesne	58,171	11.0%
Met-Ed	61,672	12.6%
PECO-Electric	163,238	11.5%
Penelec	78,117	15.5%
Penn Power	18,518	13.1%
PPL	166,536	13.7%
West Penn	45,004	7.3%
Total	**591,256**	**12.0%**

*Number of Confirmed Low-Income Natural Gas Customers**

Company	Number of Confirmed Low-Income Customers	Percent of Customers
Columbia	67,711	17.6%
Peoples	59,217	17.9%
Peoples-Equitable	43,201	17.9%
NFG	29,680	14.9%
PECO-Gas	32,170	7.0%
PGW	157,320	33.5%
UGI-Gas	39,571	12.2%
UGI Penn Natural	25,967	17.4%
Total	**454,837**	**17.8%**

*Low-income is defined as household income at or below 150 percent of FPIG.

*Number of Estimated Low-Income Electric Customers**

Company	Number of Estimated Low-Income Customers	Percent of Customers
Duquesne	132,781	25.2%
Met-Ed	118,937	24.4%
PECO-Electric	370,400	26.1%
Penelec	168,092	33.3%
Penn Power	37,776	26.8%
PPL	322,500	26.5%
West Penn	171,987	27.8%
Total	**1,322,473**	**26.9%**

*Number of Estimated Low-Income Natural Gas Customers**

Company	Number of Estimated Low-Income Customers	Percent of Customers
Columbia	95,543	24.9%
Peoples	85,820	26.0%
Peoples-Equitable	60,753	25.2%
NFG	58,908	29.6%
PECO-Gas	70,433	15.4%
PGW	186,780	39.8%
UGI-Gas	68,043	21.0%
UGI Penn Natural	38,791	26.0%
Total	**665,071**	**26.0%**

* Low-income is defined as household income at or below 150 percent of FPIG.

Termination and Reconnection of Service

Termination of utility service is the most serious consequence of customer nonpayment and is viewed as a last resort when customers fail to meet their payment obligations. The termination rate is calculated by dividing the number of service terminations by the number of residential customers, allowing for a comparison of termination activities regardless of the number of residential consumers. Any significant increase in a termination rate would indicate a trend or pattern that the Commission may need to investigate.

Reconnection of service occurs when customers either pay their debt in full or make a significant up-front payment and agree to a payment agreement for the balance owed. The ratio of reconnections to terminations is obtained by dividing the number of reconnections by the number of terminations. The result is generally indicative of the success of a customer, whose service has been terminated, at getting service reconnected.

Terminations and Reconnections - Residential Electric Customers

Company	Number of Residential Customers	Terminations	Reconnections	Termination Rate	Ratio of Reconnections to Terminations
Duquesne	526,817	25,649	20,355	4.9%	79.4%
Met-Ed	488,375	23,672	19,046	4.8%	80.5%
PECO-Electric	1,421,426	83,185	61,493	5.9%	73.9%
Penelec	504,543	20,544	16,184	4.1%	78.8%
Penn Power	141,147	4,999	4,740	3.5%	94.8%
PPL	1,218,734	47,759	34,910	3.9%	73.1%
West Penn	619,531	13,904	11,089	2.2%	79.8%
Total	**4,920,573**	**219,712**	**167,817**	**4.5%**	**76.4%**

Terminations and Reconnections - Residential Natural Gas Customers

Company	Number of Residential Customers	Terminations	Reconnections	Termination Rate	Ratio of Reconnections to Terminations
Columbia	384,213	12,030	6,490	3.1%	53.9%
Peoples	330,123	7,229	5,426	2.2%	75.1%
Peoples-Equitable	242,632	8,507	6,453	3.5%	75.9%
NFG	198,763	9,576	6,453	4.8%	67.4%
PECO-Gas	456,331	22,054	16,565	4.8%	75.1%
PGW	468,943	28,497	19,907	6.1%	69.9%
UGI-Gas	324,576	9,055	4,322	2.8%	47.7%
UGI Penn Natural	149,097	6,214	3,483	4.2%	56.1%
Total	**2,554,678**	**103,162**	**69,099**	**4.0%**	**67.0%**

*Terminations and Reconnections - Confirmed Low-Income Electric Customers**

Company	Number of Confirmed Low- Income Customers	Terminations	Reconnections	Termination Rate	Ratio of Reconnections to Terminations
Duquesne	58,171	12,671	9,932	21.8%	78.4%
Met-Ed	61,672	11,999	8,273	19.5%	68.9%
PECO-Electric	163,238	23,431	21,763	14.4%	92.9%
Penelec	78,117	11,672	8,020	14.9%	68.7%
Penn Power	18,518	2,675	2,048	14.4%	76.6%
PPL	166,536	25,950	21,849	15.6%	84.2%
West Penn	45,004	6,919	4,568	15.4%	66.0%
Total	**591,256**	**95,317**	**76,453**	**16.1%**	**80.2%**

Terminations and Reconnections - Confirmed Low-Income Natural Gas Customers*

	Number of Confirmed Low-Income Customers	Terminations	Reconnections	Termination Rate	Ratio of Reconnections to Terminations
Columbia	67,711	7,030	3,245	10.4%	46.2%
Peoples	59,217	1,373	1,031	2.3%	75.1%
Peoples-Equitable	43,201	5,477	3,969	12.7%	72.5%
NFG	29,680	5,640	3,908	19.0%	69.3%
PECO-Gas	32,170	5,191	4,837	16.1%	93.2%
PGW	157,320	18,672	13,043	11.9%	69.9%
UGI-Gas	39,571	6,674	2,832	16.9%	42.4%
UGI Penn Natural	25,968	4,552	2,051	17.5%	45.1%
Total	**454,838**	**54,609**	**34,916**	**12.0%**	**63.9%**

* Low-income is defined as household income at or below 150 percent of FPIG.

Number of Customers in Debt

Two categories exist for reporting customers overdue or in debt. The first includes customers who are on a payment agreement, and the second includes customers who are not on a payment agreement. The first category includes both PUC payment agreements and utility payment agreements. The number of customers in debt is affected by many factors, including customer income level and ability to pay, company collection practices, and the size of customer bills.

The category that a customer in debt falls into depends upon the previous factors as well as the notable addition of company collection policies. These policies include various treatments for different customer income levels.

One of the stated purposes of the Chapter 56 regulations[19] is to "provide functional alternatives to termination." One method of avoiding termination is to enter into a payment agreement[20]. Also, the fact that a customer has entered into a payment agreement means the customer is aware of the outstanding debt, has acknowledged this to the utility and has agreed to a plan to address the debt.

Two factors affect the uniformity of the data reported regarding the number of overdue customers and the dollars in debt associated with those customers. First, companies use different methods for determining when an account is overdue. Companies consider either the due date of the bill or the transmittal date of the bill to be day zero. The transmittal date is 20 days before the due date. Companies are requested to consider the due date as day zero and to report debt that is at least 30 days overdue.

Duquesne Light, Met-Ed, Penelec, Penn Power, Columbia, Equitable, UGI Penn Natural and UGI-Gas reported according to the method requested. The variance among the other EDCs and NGDCs shows a difference of no more than 20 days from that method. PECO Electric and Gas, PPL, West Penn Power, Peoples and PGW report debt that is 10 days old , meaning these companies are overstating the debt compared to companies that reported debt as 30 days overdue. NFG reports debt that is about 40 days old, meaning NFG is understating its debt relative to the other companies. Appendix 2 contains company specific information.

[19] 52 Pa. Code § 56.1
[20] 52 Pa. Code § 56.97

The second factor affecting the arrearage data uniformity is when a company moves a terminated account or a discontinued account from active status (included in the reporting) to inactive status (excluded from the reporting). Company collection policies and accounting practices affect the timing. Appendix 3 contains company specific information.

CAP recipients are excluded from all data tables referencing the number of customers in debt, the dollars in debt, and gross residential write-offs.

Number of Residential Electric Customers in Debt

Company	Number of Customers in Debt on an Agreement*	Number of Customers in Debt Not on an Agreement*	Total Number of Customers in Debt*
Duquesne	11,193	10,763	21,956
Met-Ed	25,809	19,181	44,990
PECO-Electric	24,855	95,848	120,703
Penelec	24,513	21,476	45,989
Penn Power	5,487	5,219	10,706
PPL	35,667	99,084	134,751
West Penn	17,692	26,073	43,765
Total	**145,216**	**277,644**	**422,860**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Number of Residential Natural Gas Customers in Debt

Company	Number of Customers in Debt on an Agreement*	Number of Customers in Debt Not on an Agreement*	Total Number of Customers in Debt*
Columbia	16,394	13,763	30,157
Peoples	11,126	18,973	30,099
Peoples-Equitable	8,087	10,739	18,826
NFG	4,578	5,233	9,811
PECO-Gas	8,885	22,794	31,679
PGW	18,872	58,967	77,839
UGI-Gas	4,923	24,611	29,534
UGI Penn Natural	3,423	11,485	14,908
Total	**76,288**	**166,565**	**242,853**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Customers in Debt

The percent of customers in debt is a useful statistic that supports the need for universal service programs. A company with a low percent of its residential customers in debt will experience better cash flow and have a better credit rating than one with a high percent of its residential customers in debt. The percent of customers in debt is calculated by dividing the number of customers in debt by the total number of residential customers. This calculation is done for both groups of customers in debt – those on a payment agreement and those not on a payment agreement.

Percent of Total Residential Electric Customers in Debt

Company	Percent of Total Customers in Debt on an Agreement*	Percent of Total Customers in Debt Not on an Agreement*	Total Percent of Customers in Debt*
Duquesne	2.1%	2.0%	4.2%
Met-Ed	5.3%	3.9%	9.2%
PECO-Electric	1.7%	6.7%	8.5%
Penelec	4.9%	4.3%	9.1%
Penn Power	3.9%	3.7%	7.6%
PPL	2.9%	8.1%	11.1%
West Penn	2.9%	4.2%	7.1%
Total	**3.0%**	**5.6%**	**8.6%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Total Residential Natural Gas Customers in Debt

Company	Percent of Total Customers in Debt on an Agreement*	Percent of Total Customers in Debt Not on an Agreement*	Total Percent of Customers in Debt*
Columbia	4.3%	3.6%	7.8%
Peoples	3.4%	5.7%	9.1%
Peoples-Equitable	3.3%	4.4%	7.8%
NFG	2.3%	2.6%	4.9%
PECO-Gas	1.9%	5.0%	6.9%
PGW	4.0%	12.6%	16.6%
UGI-Gas	1.5%	7.6%	9.1%
UGI Penn Natural	2.3%	7.7%	10.0%
Total	**3.0%**	**6.5%**	**9.5%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Residential Customer Debt in Dollars Owed

The amount of money owed has an impact on company expenses, making up part of the company's distribution charge.

Dollars in Debt - Residential Electric Customers

Company	Dollars in Debt on an Agreement*	Dollars in Debt Not on an Agreement*	Total Dollars in Debt*
Duquesne	$6,881,436	$4,390,065	$11,271,501
Met-Ed	$19,375,229	$4,365,518	$23,740,747
PECO-Electric	$13,362,308	$39,668,475	$53,030,783
Penelec	$16,991,387	$4,024,969	$21,016,356
Penn Power	$4,050,249	$964,919	$5,015,168
PPL	$17,617,784	$65,872,581	$83,490,365
West Penn	$8,218,767	$4,206,199	$12,424,966
Total	**$86,497,160**	**$123,492,726**	**$209,989,886**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Dollars in Debt - Residential Natural Gas Customers

Company	Dollars in Debt on an Agreement*	Dollars in Debt Not on an Agreement*	Total Dollars in Debt*
Columbia	$8,774,849	$1,568,483	$10,343,332
Peoples	$5,647,084	$6,140,079	$11,787,163
Peoples-Equitable	$4,763,070	$1,830,851	$6,593,921
NFG	$1,896,601	$1,592,750	$3,489,351
PECO-Gas	$5,672,624	$13,034,765	$18,707,389
PGW	$14,191,562	$32,775,629	$46,967,191
UGI-Gas	$1,885,351	$5,298,958	$7,184,309
UGI Penn Natural	$1,533,592	$3,448,629	$4,982,221
Total	**$44,364,733**	**$65,690,144**	**$110,054,877**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Dollars in Debt - Confirmed Low-Income Electric Customers

Company	Dollars in Debt on an Agreement*	Dollars in Debt Not on an Agreement*	Total Dollars in Debt*
Duquesne	$1,831,381	$3,971,232	$5,802,613
Met-Ed	$12,491,100	$1,432,428	$13,923,528
PECO-Electric	$2,926,340	$8,961,442	$11,887,782
Penelec	$11,990,862	$1,630,552	$13,621,414
Penn Power	$2,837,341	$350,002	$3,187,343
PPL	$12,622,149	$45,838,694	$58,460,843
West Penn	$5,049,855	$1,201,202	$6,251,057
Total	**$49,749,028**	**$63,385,552**	**$113,134,580**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Dollars in Debt- Confirmed Low-Income Natural Gas Customers

Company	Dollars in Debt on an Agreement*	Dollars in Debt Not on an Agreement*	Total Dollars in Debt*
Columbia	$5,282,905	$628,897	$5,911,802
Peoples	$3,412,550	$3,402,725	$6,815,275
Peoples-Equitable	$3,268,826	$875,335	$4,144,161
NFG	$1,229,077	$915,782	$2,144,859
PECO-Gas	$1,031,022	$2,989,994	$4,021,016
PGW	$2,288,750	$6,105,622	$8,394,372
UGI-Gas	$1,684,812	$3,133,749	$4,818,561
UGI Penn Natural	$1,348,443	$2,207,866	$3,556,309
Total	**$19,546,385**	**$20,259,970**	**$39,806,355**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Total Dollars Owed – On an Agreement Versus Not on an Agreement

The percent of dollars owed in the two reporting categories is calculated by dividing the total dollars owed in a category by the overall total dollars owed.

Percent of Debt on an Agreement - Residential Electric Customers

Company	Percent of Dollars Owed – On an Agreement*	Percent of Dollars Owed – Not on an Agreement*
Duquesne	61.1%	38.9%
Met-Ed	81.6%	18.4%
PECO-Electric	25.2%	74.8%
Penelec	80.8%	19.2%
Penn Power	80.8%	19.2%
PPL	21.1%	78.9%
West Penn	66.1%	33.9%
Total	**41.2%**	**58.8%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Debt on an Agreement - Residential Natural Gas Customers

Company	Percent of Dollars Owed – On an Agreement*	Percent of Dollars Owed – Not on an Agreement*
Columbia	84.8%	15.2%
Peoples	47.9%	52.1%
Peoples-Equitable	72.2%	27.8%
NFG	54.4%	45.6%
PECO-Gas	30.3%	69.7%
PGW	30.2%	69.8%
UGI-Gas	26.2%	73.8%
UGI Penn Natural	30.8%	69.2%
Total	**40.3%**	**59.7%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Average Arrearage

Average arrearage is calculated by dividing the total dollars in debt by the number of customers in debt. Larger average arrearages may take more time for customers to pay off and pose more of an uncollectible risk than smaller average arrearages.

Average Arrearage – Residential Electric Customers

Company	Average Arrearage on an Agreement*	Average Arrearage Not on an Agreement*	Overall Average Arrearage*
Duquesne	$614.80	$407.88	$513.38
Met-Ed	$750.72	$227.60	$527.69
PECO-Electric	$537.61	$413.87	$439.35
Penelec	$693.16	$187.42	$456.99
Penn Power	$738.15	$184.89	$468.44
PPL	$493.95	$664.82	$619.59
West Penn	$464.55	$161.32	$283.90
Total	**$595.64**	**$444.79**	**$496.59**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Average Arrearage - Residential Natural Gas Customers

Company	Average Arrearage on an Agreement*	Average Arrearage Not on an Agreement*	Overall Average Arrearage*
Columbia	$535.25	$113.96	$342.98
Peoples	$507.56	$323.62	$391.62
Peoples-Equitable	$588.98	$170.49	$350.26
NFG	$414.29	$304.37	$355.66
PECO-Gas	$638.45	$571.85	$590.53
PGW	$751.99	$555.83	$603.39
UGI-Gas	$382.97	$215.31	$243.26
UGI Penn Natural	$448.03	$300.27	$334.20
Total	**$581.54**	**$394.38**	**$453.17**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Number of Payment Agreements

A payment agreement[21] is an agreement in which a customer who admits liability for billed service is permitted to pay the unpaid balance in one or more payments. The method[22] by which utilities determine the total number of payment agreements for reporting also takes into consideration the limitations in documenting and tracking payment agreements. This results in treating a broken payment agreement that is reinstated due to a "catch-up" payment as a new payment agreement. The PUC payment agreement requests are included in this category. However, CAP payment plans are not included in the count of payment agreements.

The following tables reflect year-end payment agreement totals, and include both all residential and confirmed low-income categories to allow for the presentation of the percent of payment agreements which are confirmed low-income.

Electric Payment Agreements

Company	All Residential	Confirmed Low Income	Percent of Payment Agreements which are Confirmed Low Income
Duquesne	144,169	45,942	31.9%
Met-Ed	49,553	30,953	62.5%
PECO-Electric	66,341	11,010	16.6%
Penelec	45,737	31,731	69.4%
Penn Power	9,171	6,299	68.7%
PPL	186,389	109,043	58.5%
West Penn	41,487	24,556	59.2%
Total	**542,847**	**259,534**	**47.8%**

Natural Gas Payment Agreements

Company	All Residential	Confirmed Low Income	Percent of Payment Agreements which are Confirmed Low Income
Columbia	27,218	18,069	66.4%
Peoples	18,919	9,353	49.4%
Peoples-Equitable	14,929	8,747	58.6%
NFG	22,113	14,219	64.3%
PECO-Gas	23,556	4,114	17.5%
PGW	71,997	37,883	52.6%
UGI-Gas	29,063	24,416	84.0%
UGI Penn Natural	18,789	15,604	83.0%
Total	**226,584**	**132,405**	**58.4%**

---

[21] 52 Pa. Code, Chapter 56

[22] 52 Pa. Code § 54.75(1)(i) or § 62.5(a)(1)(i)

Payment Troubled Customers

A payment troubled customer is a customer who has failed to maintain one or more payment arrangements in a 1-year period.[23] The PUC can only offer a payment arrangement to a payment troubled customer when all "catch-up" arrears are paid, or when a previous arrangement has been satisfied. The companies have no restrictions on the number or terms of any payment arrangements they may choose to offer to payment troubled customers.

The following tables reflect an average of the 12 months of month-end data reported by the companies for payment troubled customer totals,[24] and include both all residential and confirmed low-income categories to allow for the presentation of the percent of payment troubled customers which are confirmed low-income.

Electric Payment Troubled Customers

Company	All Residential	Confirmed Low Income	Percent of Payment Troubled Customers which are Confirmed Low Income
Duquesne	10,763	4,942	45.9%
Met-Ed	1,374	923	67.2%
PECO-Electric	4,097	463	11.3%
Penelec	1,279	924	72.2%
Penn Power	278	198	71.2%
PPL	139,761	86,756	62.1%
West Penn	964	613	63.6%
Total	**158,516**	**94,819**	**59.8%**

Natural Gas Payment Troubled Customers

Company	All Residential	Confirmed Low Income	Percent of Payment Troubled Customers which are Confirmed Low Income
Columbia	13,793	8,969	65.0%
Peoples	17,930	7,302	40.7%
Peoples-Equitable	1,250	723	57.8%
NFG	4,874	2,888	59.3%
PECO-Gas	1,269	97	7.6%
PGW	27,366	15,695	57.4%
UGI-Gas	10,256	9,007	87.8%
UGI Penn Natural	6,375	5,620	88.2%
Total	**83,113**	**50,301**	**60.5%**

[23] 52 Pa. Code § 54.72 or § 62.2
[24] 52 Pa. Code § 54.75(1)(vii) or § 62.5(a)(1)(x)

Gross Residential Write-Offs in Dollars

The tables below represent the gross residential write-offs in dollars for EDCs and NGDCs in 2013. Write-offs are the final treatment of overdue accounts. A residential account is written off after all pre-write-off collection actions are taken and the customer fails to make payment on the balance owed. Generally, a company writes off accounts on either a monthly or annual basis.

Gross Write-Offs - Residential Electric Customers

Company	Gross Dollars Written Off*
Duquesne	$5,258,566
Met-Ed	$10,760,304
PECO-Electric	$38,006,588
Penelec	$8,990,906
Penn Power	$1,873,734
PPL	$53,609,736
West Penn	$6,072,775
Total	**$124,572,609**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs - Residential Natural Gas Customers

Company	Gross Dollars Written Off*
Columbia	$6,630,827
Peoples	$10,678,789
Peoples-Equitable	$4,786,037
NFG	$3,458,420
PECO-Gas	$2,268,138
PGW	$49,563,281
UGI-Gas	$4,756,334
UGI Penn Natural	$2,664,482
Total	**$84,806,308**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs - Confirmed Low-Income Electric Customers

Company	Gross Dollars Written Off*
Duquesne	$1,581,456
Met-Ed	$7,821,228
PECO-Electric	$6,313,898
Penelec	$6,886,109
Penn Power	$1,440,982
PPL	$36,879,386
West Penn	$4,006,308
Total	**$64,929,367**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs - Confirmed Low-Income Natural Gas Customers

Company	Gross Dollars Written Off*
Columbia	$4,297,201
Peoples	$2,028,969
Peoples-Equitable	$3,780,969
NFG	$2,426,706
PECO-Gas	$1,981,652
PGW	$30,120,027
UGI-Gas	$3,685,628
UGI Penn Natural	$2,444,972
Total	**$50,766,124**

*Does not include CAP Credits or Arrearage Forgiveness.

Percentage of Gross Residential Billings Written Off as Uncollectible

The percentage of residential billings written off as uncollectible is the most commonly used long-term measure of collection system performance. This measure is calculated by dividing the annual total gross dollars written off for residential accounts by the annual total dollars of residential billings. The measure offers an equitable basis for comparison of gross residential dollars written-off to the annual total dollars of residential billings.

Gross Write-Offs Ratio - Residential Electric Customers

Company	Gross Write-Offs Ratio*
Duquesne	1.3%
Met-Ed	1.9%
PECO-Electric	1.9%
Penelec	1.9%
Penn Power	1.3%
PPL	3.1%
West Penn	1.2%
Total	**2.1%**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs Ratio - Residential Natural Gas Customers

Company	Gross Write-Offs Ratio*
Columbia	2.0%
Peoples	3.6%
Peoples-Equitable	1.9%
NFG	2.2%
PECO-Gas	0.5%
PGW	10.4%
UGI-Gas	2.2%
UGI Penn Natural	1.6%
Total	**3.7%**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs Ratio - Confirmed Low-Income Electric Customers

Company	Gross Write-Offs Ratio*
Duquesne	2.6%
Met-Ed	9.3%
PECO-Electric	5.5%
Penelec	7.7%
Penn Power	6.7%
PPL	12.4%
West Penn	7.9%
Total	**9.0%**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs Ratio - Confirmed Low-Income Natural Gas Customers

Company	Gross Write-Offs Ratio*
Columbia	7.7%
Peoples	2.6%
Peoples-Equitable	10.0%
NFG	12.5%
PECO-Gas	11.6%
PGW	24.8%
UGI-Gas	11.6%
UGI Penn Natural	8.3%
Total	**13.0%**

*Does not include CAP Credits or Arrearage Forgiveness.

Annual Collection Operating Expenses

Annual collection operating expenses include administrative expenses associated with termination activity; negotiating payment agreements; budget counseling; investigation and resolution of informal and formal complaints associated with payment agreements; securing and maintaining deposits; tracking delinquent accounts; collection agencies' expenses; litigation expenses other than Commission-related; dunning expenses[25]; and, winter survey expense. CAP recipient collection expenses are excluded.

The tables below include both the All Residential and Confirmed Low-Income categories to allow for the presentation of the percent of annual collection operating expenses which are attributed to confirmed low-income.

[25] Dunning, in the business context, refers to the collections process, whereby a business communicates with customers who have fallen behind in paying their bills.

Annual Electric Collection Operating Expenses

Company	All Residential	Confirmed Low Income	Percent of Collection Operating Expenses which are for Confirmed Low-Income Customers
Duquesne	$12,918,873	$10,141,497	78.5%
Met-Ed	$14,174,470	$9,364,711	66.1%
PECO-Electric	$14,834,072	$1,849,114	12.5%
Penelec	$12,431,170	$8,631,392	69.4%
Penn Power	$2,860,186	$1,926,158	67.3%
PPL	$15,414,244	$8,169,549	53.0%
West Penn	$8,464,260	$4,875,850	57.6%
Total	**$81,097,275**	**$44,958,271**	**55.4%**

Annual Natural Gas Collection Operating Expenses

Company	All Residential	Confirmed Low Income	Percent of Collection Operating Expenses which are for Confirmed Low-Income Customers
Columbia	$2,300,518	$1,306,451	56.8%
Peoples	$2,880,864	$749,024	26.0%
Peoples-Equitable	$2,409,090	$431,322	17.9%
NFG	$596,785	$251,793	42.2%
PECO-Gas	$1,833,425	$124,205	6.8%
PGW	$1,249,782	$419,274	33.5%
UGI-Gas	$2,264,783	$1,902,417	84.0%
UGI Penn Natural	$831,413	$690,477	83.0%
Total	**$14,366,660**	**$5,874,963**	**40.9%**

Selected Tables for Multi-Year Data

Terminations - Residential Electric Customers

Company	2012 Terminations	2013 Terminations	Change 2012-13	2012 Termination Rate	2013 Termination Rate
Duquesne	23,533	25,649	9.0%	4.5%	4.9%
Met-Ed	17,995	23,672	31.5%	3.7%	4.8%
PECO-Electric	73,344	83,185	13.4%	5.2%	5.9%
Penelec	13,747	20,544	49.4%	2.7%	4.1%
Penn Power	3,514	4,999	42.3%	2.5%	3.5%
PPL	38,303	47,759	24.7%	3.2%	3.9%
West Penn	11,092	13,904	25.4%	1.8%	2.2%
Total	**181,528**	**219,712**	**21.0%**	**3.7%**	**4.5%**

Terminations - Residential Natural Gas Customers

Company	2012 Terminations	2013 Terminations	Change 2012-13	2012 Termination Rate	2013 Termination Rate
Columbia	11,321	12,030	6.3%	3.0%	3.1%
Peoples	6,601	7,229	9.5%	2.0%	2.2%
Peoples-Equitable	8,394	8,507	1.3%	3.5%	3.5%
NFG	8,347	9,576	14.7%	4.2%	4.8%
PECO-Gas	20,411	22,054	8.0%	4.5%	4.8%
PGW	25,507	28,497	11.7%	5.3%	6.1%
UGI-Gas	8,434	9,055	7.4%	2.7%	2.8%
UGI Penn Natural	5,403	6,214	15.0%	3.7%	4.2%
Total	**94,418**	**103,162**	**9.3%**	**3.7%**	**4.0%**

Exhibit JH-8

Number of Residential Electric Customers in Debt

Company	2012 Total Number of Customers in Debt*	2013 Total Number of Customers in Debt*	Change 2012-13
Duquesne	21,965	21,956	0.0%
Met-Ed	46,622	44,990	-3.5%
PECO-Electric**	118,675	120,703	1.7%
Penelec	46,649	45,989	-1.4%
Penn Power	10,575	10,706	1.2%
PPL	134,823	134,751	-0.1%
West Penn	51,529	43,765	-15.1%
Total	**430,838**	**422,860**	**-1.9%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 142,434 has been revised to exclude CAP, consistent with reporting requirements.

Number of Residential Natural Gas Customers in Debt

Company	2012 Total Number of Customers in Debt*	2013 Total Number of Customers in Debt*	Change 2012-13
Columbia	36,940	30,157	-18.4%
Peoples	32,701	30,099	-8.0%
Peoples-Equitable	17,468	18,826	7.8%
NFG	9,744	9,811	0.7%
PECO-Gas**	30,988	31,679	2.2%
PGW	61,640	77,839	26.3%
UGI-Gas	25,903	29,534	14.0%
UGI Penn Natural	13,209	14,908	12.9%
Total	**228,593**	**242,853**	**6.2%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 35,039 has been revised to exclude CAP, consistent with reporting requirements.

Dollars in Debt - Residential Electric Customers

Company	2012 Total Dollars in Debt*	2013 Total Dollars in Debt*	Change 2012-13
Duquesne	$11,004,856	$11,271,501	2.4%
Met-Ed	$27,405,440	$23,740,747	-13.4%
PECO-Electric**	$51,297,270	$53,030,783	3.4%
Penelec	$23,715,969	$21,016,356	-11.4%
Penn Power	$5,899,156	$5,015,168	-15.0%
PPL	$79,988,700	$83,490,365	4.4%
West Penn	$10,589,845	$12,424,966	17.3%
Total	**$209,901,235**	**$209,989,886**	**0.0%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of $76,791,682 has been revised to exclude CAP, consistent with reporting requirements.

Dollars in Debt - Residential Natural Gas Customers

Company	2012 Total Dollars in Debt*	2013 Total Dollars in Debt*	Change 2012-13
Columbia	$8,569,783	$10,343,332	20.7%
Peoples	$15,012,948	$11,787,163	-21.5%
Peoples-Equitable	$6,047,220	$6,593,921	9.0%
NFG	$3,759,476	$3,489,351	-7.2%
PECO-Gas**	$18,670,937	$18,707,389	0.2%
PGW	$36,314,051	$46,967,191	29.3%
UGI-Gas	$5,595,669	$7,184,309	28.4%
UGI Penn Natural	$3,925,932	$4,982,221	26.9%
Total	**$97,896,015**	**$110,054,877**	**12.4%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of $21,441,745 has been revised to exclude CAP, consistent with reporting requirements.

Gross Write-Offs - Residential Electric Customers

Company	2012 Gross Dollars Written Off*	2013 Gross Dollars Written Off*	Change 2012-13
Duquesne	$6,650,626	$5,258,566	-20.9%
Met-Ed	$14,247,722	$10,760,304	-24.5%
PECO-Electric	$39,759,812	$38,006,588	-4.4%
Penelec	$10,884,926	$8,990,906	-17.4%
Penn Power	$2,562,389	$1,873,734	-26.9%
PPL	$50,505,800	$53,609,736	6.1%
West Penn	$6,545,769	$6,072,775	-7.2%
Total	**$131,157,044**	**$124,572,609**	**-5.0%**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs - Residential Natural Gas Customers

Company	2012 Gross Dollars Written Off*	2013 Gross Dollars Written Off*	Change 2012-13
Columbia	$7,585,766	$6,630,828	-12.6%
Peoples**	$691,264	$10,678,789	1,444.8%
Peoples-Equitable	$3,967,617	$4,786,037	20.6%
NFG	$3,844,868	$3,458,420	-10.1%
PECO-Gas	$2,620,174	$2,268,138	-13.4%
PGW	$39,102,990	$49,563,281	26.8%
UGI-Gas	$4,485,688	$4,756,334	6.0%
UGI Penn Natural	$2,637,351	$2,664,482	1.0%
Total	**$64,935,718**	**$84,806,309**	**30.6%**

*Does not include CAP Credits or Arrearage Forgiveness.

** Peoples' write offs were minimal in 2012 due to the conversion to a new billing system.

Gross Write-Offs Ratio - Residential Electric Customers

Company	2012 Gross Write-Offs Ratio*	2013 Gross Write-Offs Ratio*	Change 2012-13
Duquesne	1.4%	1.3%	-7.1%
Met-Ed	2.4%	1.9%	-20.8%
PECO-Electric	2.0%	1.9%	-5.0%
Penelec	2.1%	1.9%	-9.5%
Penn Power	1.7%	1.3%	-23.5%
PPL	3.2%	3.1%	-3.1%
West Penn	1.3%	1.2%	-7.7%
Total	**2.2%**	**2.1%**	**-4.5%**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs Ratio - Residential Natural Gas Customers

Company	2012 Gross Write-Offs Ratio*	2013 Gross Write-Offs Ratio*	Change 2012-13
Columbia	2.8%	2.0%	-28.6%
Peoples**	0.3%	3.6%	1,200.0%
Peoples-Equitable	1.9%	1.9%	0.0%
NFG	2.6%	2.2%	-15.4%
PECO-Gas	0.7%	0.5%	-28.6%
PGW	9.1%	10.4%	14.3%
UGI-Gas	2.3%	2.2%	-4.3%
UGI Penn Natural	1.8%	1.6%	-11.1%
Total	**3.2%**	**3.7%**	**15.6%**

* Does not include CAP Credits or Arrearage Forgiveness.

** Peoples' write offs were minimal in 2012 due to the conversion to a new billing system.

Percent of Revenues (Billings) in Debt

The percent of revenues (billings) in debt is calculated by dividing the total annual revenues (billings) by the total monthly average dollars in debt. This calculated variable provides another way to measure the extent of customer debt. In the following two tables, the higher the percentage, the greater the potential collection risk.

Percent of Revenues (Billings) in Debt - Residential Electric Customers

Company	2012	2013	Change 2012-13
Duquesne	2.3%	2.8%	21.7%
Met-Ed	4.6%	4.2%	-8.7%
PECO-Electric**	2.5%	2.6%	4.0%
Penelec	4.6%	4.4%	-4.3%
Penn Power	3.9%	3.6%	-7.7%
PPL	5.0%	4.8%	-4.0%
West Penn	2.0%	2.5%	25.0%
Total	**3.6%**	**3.6%**	**0.0%**

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 3.8% has been revised to exclude CAP, consistent with reporting requirements.

Percent of Revenues (Billings) in Debt - Residential Natural Gas Customers

Company	2012	2013	Change 2012-13
Columbia	3.2%	3.1%	-3.1%
Peoples	6.0%	3.9%	-35.0%
Peoples-Equitable	2.9%	2.7%	-6.9%
NFG	2.5%	2.2%	-12.0%
PECO-Gas**	5.0%	4.4%	-12.0%
PGW	8.4%	9.9%	17.9%
UGI-Gas	2.8%	3.3%	17.9%
UGI Penn Natural	2.7%	3.0%	11.1%
Total	**4.8%**	**4.7%**	**-2.0%**

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 5.7% has been revised to exclude CAP, consistent with reporting requirements.

3. Universal Service Programs

Demographics

The USRR requires EDCs and NGDCs to report the demographics of program recipients, including the number of household members under age 18 and over age 62, household size, income, and source of income. A low-income customer is defined[26] as a residential utility customer whose household income is at or below 150 percent of FPIG. Appendix 4 shows poverty levels in relation to household size and income.

Source of Income, Average Household Size and Income

For all 2013 universal service program customers (both electric and gas), average household incomes are below $16,526. Electric and natural gas households receiving CAP benefits in 2013 have average household incomes that are less than $12,914 per year. Electric customers who receive LIURP service have average yearly household incomes at $16,455, while gas customers average $16,629. These households average three persons, with at least one member under 18 years old. Average household incomes for universal service and energy conservation program participants are well below 150 percent of FPIG for three persons ($29,295 in 2013; $29,685 in 2014). See Appendix 4.

The majority of electric and gas customers participating in universal service programs have incomes from employment, disability benefits or pension benefits. See Appendix 5 for a summary of the source of income data.

"Working poor" households do not always have incomes that exceed 150 percent of FPIG. A definition of a "working poor" household begins with a wage-earner who works full time at a minimum-wage job. In 2013, minimum wage was $7.25 per hour, the same as it was in 2011 and 2012.[27] Annual income for a wage earner who works at a minimum-wage job is $15,080. A typical 2013 CAP customer (household) has an income of approximately $12,900, which places these households' incomes at about 66 percent of FPIG (for three persons) for 2013, and 65 percent for 2014.

Finally, it is important to understand the relationship between household income and the percent of income a household spends on energy. Energy burden was defined in 2002 as the percentage of household income that a household spends on total home energy needs.[28] In most instances without CAP programs, calculations made using the 2012 median income for Pennsylvania[29] show CAP eligible households would pay about 15 percent of their household income for energy compared with a typical Pennsylvania household that pays about 3.8 percent of its income for home energy needs.

---

[26] 52 Pa. Code § 54.72

[27] http://www.dol.gov/whd/minwage/america.htm The Pennsylvania state minimum wage law adopts the federal minimum wage rate by reference.

[28] U.S. Department of Health & Human Services, LIHEAP Home Energy Notebook for FY 2002: Appendix A Home energy estimates, p.45, 2004.

[29] http://www.deptofnumbers.com/income/pennsylvania/ Derived from Census ACS 1-yr survey.

Participants in Universal Service Programs
Average Household Income – Summary for All Electric Customers

	2012	2013
LIURP	$16,685	$16,455
CAP	$14,350	$13,524
CARES	$18,441	$16,088
Hardship Fund	$20,825	$24,464

Participants in Universal Service Programs
Average Household Income –Summary for All Natural Gas Customers

	2012	2013
LIURP	$16,104	$16,629
CAP	$12,061	$12,304
CARES	$15,207	$15,988
Hardship Fund	$16,322	$16,755

Low Income Usage Reduction Program (LIURP)

LIURP is a statewide, utility-sponsored, residential usage-reduction program mandated by the PUC[30]. The primary goal of LIURP is to assist low-income residential customers to reduce energy bills through usage reduction (energy conservation) and, as a result, to make bills more affordable.

LIURP is targeted toward customers with annual incomes at or below 150 percent of FPIG. However, companies are permitted to spend up to 20 percent of their annual LIURP budgets on customers with incomes between 150 percent and 200 percent of FPIG. LIURP places priority on the highest energy users who offer the greatest opportunities for bill reductions. Generally, EDCs target customers with annual usage of at least 6,000 kWhs, and NGDCs target customers with annual usage of at least 120 Mcfs. When feasible, the program targets customers with payment problems (arrearages). The program is available to both homeowners and renters. LIURP services all housing types, including single family homes, mobile homes, and small and large multi-family residences.

The LIURP funds are included in utility rates as part of the distribution cost passed on to all residential customers. The current LIURP funding levels were set for three years in the company's most recently filed universal service plans, which are to be filed every three years. The utility is required to develop a funding level based upon a needs assessment, which, in turn, will likely be based on census and utility data.

The PUC has regulatory oversight of LIURP, and the utilities administer the program using both non-profit and for-profit contractors. The various program costs and installed usage reduction measures are agreed to in contracts between the contractors and the utilities.

Program measures are installed on a simple payback recovery basis of seven years or less for most program measures. Some exceptions must meet a 12-year simple payback recovery. The exceptions include sidewall insulation, attic insulation, furnace replacement, water heater replacement and refrigerator replacement. Recovery is

[30] 52 Pa. Code, Chapter 58

the time it takes to recover the cost of the installed program measure through projected energy savings. Examples of the program measures include: air infiltration measures using the blower door air sealing techniques, all types of insulation such as attic and sidewall, heating system treatments and replacements, water heating tank and pipe wraps, water heater replacements, compact fluorescent lighting, refrigerator replacement, water bed replacement with a form-fitted foam mattress, incidental repairs (not home rehabilitation), and conservation education.

The factors impacting energy savings are: the level of pre-weatherization usage, occupant energy behavior, housing type and size, age of the dwelling, condition of the dwelling, end uses such as heating, cooling, and water heating, and contractor capabilities.

LIURP benefits include: bill reduction, improved health, safety and comfort levels, LIHEAP leveraging (Pennsylvania receives additional funds due to the LIURP resources that supplement LIHEAP funds), arrearage reduction, reduced collection activity, improved bill payment behavior, reduced use of supplemental fuels and secondary heating devices, more affordable low-income housing, reduction in homelessness, and less housing abandonment.

The USRR provisions require reporting various LIURP data, including: annual program costs for the reporting year, number of family members under 18 years of age, number of family members over 62 years of age, family size, household income, source of income, participation levels for the reporting year, projected annual spending for the current year, projected annual participation levels for the current year, and average job costs.

In addition, this report also includes data on completed jobs provided by EDCs and NGDCs in accordance with the LIURP Codebook[31].

[31] Originally based in the LIURP regulations at 52 Pa. Code § 58.15 and incorporated in the Universal Service Reporting Requirements regulations

LIURP Spending

As a rule, companies try to spend all LIURP funds budgeted each year, but this is not always possible. In most cases, unspent funds are carried over from one program year to the next on an ongoing basis.

LIURP Spending - Electric Utilities

Company	2013 Actual Spending	2014 Projected Spending*
Duquesne	$1,707,828	$1,364,600
Met-Ed	$3,360,707	$4,008,418
PECO-Electric	$5,600,000	$5,600,000
Penelec	$4,004,785	$4,845,570
Penn Power	$1,534,568	$2,348,152
PPL	$8,233,448	$9,500,000
West Penn	$2,676,644	$3,432,305
Total	**$27,117,980**	**$31,099,045**

*Includes carryover of unspent funds.

LIURP Spending - Natural Gas Utilities

Company	2013 Actual Spending	2014 Projected Spending*
Columbia	$4,363,318	$4,511,758
Peoples	$1,100,000	$1,250,000
Peoples-Equitable	$926,319	$801,551
NFG	$1,533,989	$1,232,230
PECO-Gas	$2,250,000	$2,250,000
PGW	$8,054,404	$7,458,722
UGI-Gas	$438,032	$660,224
UGI Penn Natural	$957,294	$921,605
Total	**$19,623,356**	**$19,086,090**

* Includes carryover of unspent funds.

LIURP Production

LIURP production levels are influenced by many factors including: the size of the company's LIURP program budget; the heating saturation among the company's customer population; housing-stock characteristics such as the type, size, and condition; contractor capability; contractor capacity; and to a lesser extent, customer demographics and customer behavior.

LIURP Electric Production

Company	2013 Actual Production			2014 Projected Production		
	Heating Jobs	Water Heating Jobs	Baseload Jobs*	Heating Jobs	Water Heating Jobs	Baseload Jobs*
Duquesne	161	0	3,305	100	3	2,452
Met-Ed	704	423	363	686	414	360
PECO-Electric	1,155	0	8,320	1,060	0	8,210
Penelec	420	926	877	425	1,087	728
Penn Power	228	259	303	241	274	310
PPL	1,340	665	1,284	1,900	800	400
West Penn	333	310	166	375	373	152
Total	**4,341**	**2,583**	**14,618**	**4,787**	**2,951**	**12,612**

*Baseload jobs contain very few or no heating or water heating program measures.

LIURP Natural Gas Production

Company	2013 Actual Production Heating Jobs	2014 Projected Production Heating Jobs
Columbia	574	594
Peoples	230	254
Peoples-Equitable	152	160
NFG	227	215
PECO-Gas	1,345	1,050
PGW	2,391	2,214
UGI-Gas	78	94
UGI Penn Natural	159	132
Total	**5,156**	**4,713**

LIURP Average Job Costs

Customer usage profiles are typically highest for heating jobs followed by water heating jobs and baseload jobs. Average job costs are based on the total number of completed jobs in the job-type category and the total costs associated with those jobs. Specifically, the average job cost is calculated by dividing the total dollars spent on a type of job by the number of jobs completed.

All LIURP gas jobs are classified as heating. For electric jobs, the determination of the job type depends on whether the customer heats with electricity. If most of the dollars spent on the completed job are on heating-related program measures, then the job is classified as a heating job. If the customer does not heat with electricity but uses electricity for water heating, and most of the dollars spent on the completed job are on water-heating measures, then the job is classified as a water-heating job. If the customer does not use electricity for either heating or water heating, the completed job is automatically classified as a baseload job. This is a simplistic model for classifying the type of job, and this model is easy to apply to the vast majority of electric jobs in LIURP.

LIURP Electric Average Job Costs

Company	2013 Heating Jobs	2013 Water Heating Jobs	2013 Baseload Jobs
Duquesne	$3,784	$0	$454
Met-Ed	$2,042	$1,511	$1,364
PECO-Electric	$1,563	$0	$380
Penelec	$1,680	$1,558	$1,098
Penn Power	$1,984	$1,343	$809
PPL	$3,441	$1,619	$1,028
West Penn	$2,784	$2,280	$1,761

LIURP Natural Gas Average Job Cost

Company	2013 Heating Jobs
Columbia	$6,792
Peoples	$3,828
Peoples-Equitable	$5,012
NFG	$4,718
PECO-Gas	$1,618
PGW	$2,567
UGI-Gas	$4,330
UGI Penn Natural	$5,282

LIURP Energy Savings and Bill Reduction

LIURP energy savings are determined by calculating the difference in a customer's usage during the 12 months following the installation of the LIURP measures, from the usage during the 12 preceding months. The energy savings reported are based on weather-normalized data and represent an average of the company results.

The estimated annual bill reduction is calculated by multiplying the average number of kWhs or Mcfs saved during the post-treatment period by the average price per kWh or Mcf during that period. Companies voluntarily report pricing information annually. The estimated annual bill reductions presented are based on the average of the company results.

LIURP Energy Savings and Bill Reductions

Job Type	2011 Energy Savings	2011 Estimated Annual Bill Reduction
Electric Heating	10.9%	$267
Electric Water Heating	10.8%	$216
Electric Baseload	8.7%	$144
Gas Heating	17.5%	$394

Customer Assistance Programs (CAPs)

The PUC monitors implementation of the Commission's CAP Policy Statement and regulations[32] by the seven largest EDCs and NGDCs serving more than 100,000 customers. The USRR requires the companies to report the number of customers enrolled in CAP. The Commission defines participation as those participants enrolled in CAP at the end of the program year. As part of each company's restructuring proceeding, a program phase-in size was established. Under the USRR, each company submits for approval a three-year universal service plan. PUC regulations[33] require the companies to submit a projected needs assessment and projected enrollment level for its universal service programs. Universal Service Plans and Evaluations are posted on the Commission's website (Appendix 7 contains viewing instructions).

The CAP Participation Rate is defined as the number of participants enrolled as of Dec. 31, 2013, divided by the number of confirmed low-income customers served by the EDC or NGDC. The Commission expects a utility to maintain open enrollment to meet the need in each utility's service territory. The CAP participation rate would be much lower if the rate reflected estimated rather than confirmed low-income customers.

[32] 66 Pa. C.S. §§ 2802(10), §§ 2804(9), §§ 2203(7) and §§ 2203(8)

[33] 52 Pa. Code § 54.74 for EDCs and 52 Pa. Code §62.4 for NGDCs

Exhibit JH-8

CAP Participation - Electric Utilities

Company	2012		2013	
	Participants Enrolled as of 12/31/12	CAP Participation Rate	Participants Enrolled as of 12/31/13	CAP Participant Rate
Duquesne	36,156	63%	35,568	61%
Met-Ed	28,773	48%	17,517	28%
PECO-Electric	136,529	81%	139,677	86%
Penelec	36,848	48%	24,244	31%
Penn Power	9,246	50%	5,590	30%
PPL	31,657	20%	37,204	22%
West Penn	21,120	47%	20,607	46%
Total	**300,329**		**280,407**	
Weighted Avg.*		**52%**		**47%**

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

CAP Participation - Natural Gas Utilities

Company	2012		2013	
	Participants Enrolled as of 12/31/12	CAP Participation Rate	Participants Enrolled as of 12/31/13	CAP Participant Rate
Columbia	20,026	30%	20,103	30%
Peoples	15,612	25%	19,887	34%
Peoples-Equitable	11,534	27%	11,263	26%
NFG	10,627	35%	9,833	33%
PECO-Gas	23,284	78%	24,301	76%
PGW	75,224	50%	68,458	44%
UGI-Gas	5,041	13%	4,491	11%
UGI-Penn Natural	3,703	14%	3,588	14%
Total	**165,051**		**161,924**	
Weighted Avg.*		**37%**		**36%**

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

CAP Benefits - Bills, Credits & Arrearage Forgiveness

The USRR requires companies to report data on CAP benefits. Companies report by month the number of participants enrolled in CAP. Because CAP enrollment fluctuates during the year, the Commission bases average CAP credits and arrearage forgiveness benefits on the average monthly number of CAP participants rather than the number of CAP participants enrolled at the end of the year.

The PUC has identified the three components of CAP benefits as the average CAP bill, average CAP credits, and average arrearage forgiveness. The average CAP bill is the total CAP amount billed (total of the expected monthly CAP payment) divided by the total number of CAP bills rendered. The average CAP credit is the total amount of the difference between the standard billed amount and the CAP billed amount divided by the average monthly number of CAP participants. The average arrearage forgiveness is the total preprogram arrearages forgiven as a result of customers making agreed upon CAP payments divided by the average monthly number of CAP participants. The tables show average monthly CAP bills and CAP benefits.

Average CAP bills and CAP credits fluctuate due to several factors: CAP customers may have different payment plans based on their type of usage (heating or non-heating); change in rates; and the distribution of income levels among program participants. Consumption and weather also will affect NFG and PECO's CAP bills and credits, in particular, because the payment plan rate discounts are tied to usage.

Average Monthly Electric CAP Bill

Company	2012	2013
Duquesne	$78	$77
Met-Ed	$82	$57
PECO-Electric	$68	$69
Penelec	$71	$46
Penn Power	$46	$39
PPL	$81	$79
West Penn	$86	$85

Average Monthly Natural Gas CAP Bill

Company	2012	2013
Columbia	$51	$53
Peoples	$64	$64
Peoples-Equitable	$81	$75
NFG	$66	$74
PECO-Gas	$54	$59
PGW	$84	$82
UGI-Gas	$84	$76
UGI Penn Natural	$94	$83

Average Annual Electric CAP Credits

Company	2012	2013
Duquesne	$358	$343
Met-Ed	$780	$768
PECO-Electric	$578	$565
Penelec	$641	$653
Penn Power	$739	$655
PPL	$811	$1,034
West Penn	$227	$336

Average Annual Natural Gas CAP Credits

Company	2012	2013
Columbia	$323	$597
Peoples	$255	$308
Peoples-Equitable	$392	$550
NFG	$126	$133
PECO-Gas	$140	$174
PGW	$799	$922
UGI-Gas	$324	$461
UGI Penn Natural	$513	$519

Arrearage forgiveness credits fluctuate due to the following factors: the length of time over which forgiveness occurs; the length of time a customer is enrolled in CAP; and the amount of arrearage brought to the CAP program.

Average Annual Electric Utilities Arrearage Forgiveness

Company	2012	2013
Duquesne	$71	$75
Met-Ed	$127	$125
PECO-Electric	$87	$77
Penelec	$85	$85
Penn Power	$114	$94
PPL	$491	$468
West Penn	$130	$159

Exhibit JH-8

Average Annual Natural Gas Utilities Arrearage Forgiveness

Company	2012	2013
Columbia	$4	$28
Peoples	$86	$98
Peoples-Equitable	$27	$29
NFG	$32	$27
PECO-Gas	$34	$28
PGW	$97	$89
UGI-Gas	$78	$155
UGI Penn Natural	$106	$194

CAP Costs

The USRR requires the companies to report data on CAP program costs. The companies and the PUC developed mutually satisfactory guidelines for reporting CAP costs, which include costs for administration, CAP credits, and arrearage forgiveness. Administrative costs include: contract and utility staffing, account monitoring, intake, outreach, consumer education and conservation training, maintaining telephone lines, recertification, computer programming, evaluation, and other fixed overhead costs. Account monitoring costs include collection expenses, as well as other operation and maintenance expenses. Appendix 6 contains the percentage of CAP spending by program component.

Costs are gross costs and do not reflect any potential savings to traditional collection expenses, cash-working-capital expenses and bad debt expenses that may result from enrolling low-income customers in CAP. Appendix 8 shows total universal service costs, universal service funding mechanisms, and average annual universal service costs per residential customer.

Exhibit JH-8

CAP Electric Gross Costs

Company	2012			2013		
	Total Gross CAP Costs	Average CAP Enrollment	Average Gross Program Costs per CAP Customer	Total Gross CAP Costs	Average CAP Enrollment	Average Gross Program Costs per CAP Customer
Duquesne	$16,680,684	36,085	$462	$16,549,705	36,544	$453
Met-Ed	$28,356,979	29,574	$959	$22,984,906	23,290	$987
PECO-Electric	$94,760,602	138,691	$683	$91,708,724	138,086	$663
Penelec	$30,152,302	38,962	$774	$25,303,288	30,687	$825
Penn Power	$8,861,651	9,830	$901	$6,116,965	7,262	$842
PPL	$47,106,215	34,462	$1,337	$55,223,019	35,197	$1,569
West Penn	$8,495,135	21,965	$387	$10,768,235	20,627	$522
Total	**$234,413,568**	**309,570**		**$228,654,842**	**291,693**	
Weighted Avg.*			**$757**			**$784**

CAP Natural Gas Gross Costs

Company	2012			2013		
	Total Gross CAP Costs	Average CAP Enrollment	Average Gross Program Costs per CAP Customer	Total Gross CAP Costs	Average CAP Enrollment	Average Gross Program Costs per CAP Customer
Columbia	$8,167,972	21,137	$386	$13,272,158	19,803	$670
Peoples	$6,022,673	15,009	$401	$8,227,588	18,170	$453
Peoples-Equitable	$6,055,041	13,122	$461	$7,090,722	11,280	$629
NFG	$1,958,376	11,208	$175	$1,838,472	9,961	$185
PECO-Gas	$4,555,567	23,847	$191	$5,219,029	23,744	$220
PGW	$73,059,396	80,343	$909	$77,281,237	74,507	$1,037
UGI-Gas	$2,662,779	6,135	$434	$3,176,112	4,859	$654
UGI Penn Natural	$2,782,805	4,214	$660	$2,852,339	3,760	$759
Total	**$105,264,609**	**175,015**		**$118,957,657**	**166,084**	
Weighted Avg.*			**$601**			**$716**

*Weighted Averages are based on industry totals and do not represent an average of the participation rates shown in the tables.

CARES

The primary purpose of a CARES program is to provide a cost-effective service that helps payment troubled customers maximize their ability to pay utility bills. CARES staff provide three primary services: case management; maintaining a network of service providers; and making referrals to services that provide assistance.

As utilities have expanded their CAP programs, the focus of CARES has changed. For most utilities, CARES has become a component of CAP. The Commission has not objected to some of the functions of CARES changing over time because the expansion of CAP has reduced the number of customers who may need case management services. The utility often places those customers with unresolved hardship into CAP, where they would receive more affordable payments once enrolled.

A utility CARES representative also performs the task of strengthening and maintaining a network of community organizations and government agencies that can provide services to the program clients. By securing these services, including energy assistance funds, customers can maintain safe and adequate utility service. LIHEAP outreach and networking are vital pieces of CARES. A CARES program continues to address the important health and safety concerns relating to utility service. Finally, CARES staff conduct outreach and make referrals to programs that provide energy assistance grants, such as LIHEAP, hardship funds, and other agencies that provide cash assistance.

CARES Benefits

USSR requires companies report data on CARES benefits, defined as the total number and dollar amount of LIHEAP benefits applied to all low-income customer accounts. LIHEAP benefits include both LIHEAP cash and LIHEAP crisis grants. Typically, households that receive LIHEAP crisis grants also receive cash grants. Therefore, to avoid double counting the benefits, the table shows the number of households receiving LIHEAP cash grants. The dollar amount of LIHEAP benefits includes both cash and crisis LIHEAP benefits. The total amount of LIHEAP dollars each utility receives depends primarily on the amount of the LIHEAP appropriation to the state and the number of low-income customers in each company's service territory.

The regulations define[34] direct dollars as those applied to a CARES customer's utility account, including all sources of energy assistance such as LIHEAP, hardship fund grants, and local agencies' grants. The column "Direct Dollars in Addition to LIHEAP Grants for CARES Participants" subtracts LIHEAP benefits from total CARES benefits to show the total dollar benefits not related to LIHEAP. Net CARES benefits include LIHEAP cash and crisis grants plus direct dollars in addition to LIHEAP grants. The administrative costs of CARES are deducted from the total CARES benefits to equal net CARES benefits. Because the number of participants who receive the case management services of CARES is small, the direct dollars not related to LIHEAP grants will be a smaller number than the total LIHEAP dollars for all low-income customers.

[34] 52 Pa. Code § 54.72. Definitions.

Exhibit JH-8

2013 Electric CARES Benefits

Company	CARES Costs	Total LIHEAP Grants for Low-Income Customers*	Low-Income Households who Received LIHEAP Cash Grants	Direct Dollars in Addition to LIHEAP Grants for CARES Participants	Net CARES Benefits
Duquesne	$125,000	$4,366,719	14,391	$294,330	$4,536,049
Met-Ed**	$0	$2,088,990	7,511	$0	$2,088,990
PECO-Electric	$1,239,254	$12,673,475	37,091	$183,260	$11,617,481
Penelec**	$0	$2,913,452	9,378	$0	$2,913,452
Penn Power**	$0	$716,042	2,228	$0	$716,042
PPL	$0	$7,548,901	25,479	$77,224	$7,626,125
West Penn	$0	$3,528,148	11,657	$0	$3,528,148
Total	**$1,364,254**	**$33,835,727**	**107,735**	**$554,814**	**$33,026,287**

*Total LIHEAP grants include both LIHEAP cash and crisis grants. Typically, customers who receive crisis grants also receive cash grants.

**Met-Ed, Penelec and Penn Power enroll and monitor all CARES participants in CAP rather than separately monitoring these accounts. PPL includes the costs of CARES in its OnTrack costs. The CARES representatives in each of these companies perform the functions of both CAP and CARES.

2013 Natural Gas CARES Benefits

Company	CARES Costs	Total LIHEAP Grants for Low-Income Customers*	Low-Income Households who Received LIHEAP Cash Grants	Direct Dollars in Addition to LIHEAP Grants for CARES Participants	Net CARES Benefits
Columbia	$395,733	$6,361,015	23,286	$53,571	$6,018,853
Peoples	$157,244	$4,749,723	21,424	$7,901	$4,600,380
Peoples-Equitable	$226,294	$4,472,601	14,477	$80,541	$4,326,848
NFG	$3,211	$6,276,711	20,177	$184	$6,273,684
PECO-Gas	$185,176	$1,893,738	5,542	$27,383	$1,735,945
PGW	$668,031	$19,582,009	65,690	$0	$19,582,009
UGI-Gas	$74,041	$3,495,052	15,851	$782	$3,421,793
UGI Penn Natural	$33,766	$3,467,198	13,692	$2,040	$3,435,472
Total	**$1,743,496**	**$50,298,047**	**180,139**	**$172,402**	**$49,394,984**

*Total LIHEAP grants include both LIHEAP cash and crisis grants. Typically, customers who receive crisis grants also receive cash grants.

Utility Hardship Fund Programs

Utility company hardship funds provide cash assistance to utility residential customers who need help in paying their utility bills or to those who still have a critical need for assistance after other resources have been exhausted. The funds make payments directly to companies on behalf of eligible customers.

Ratepayer and Shareholder Contributions

The USSR requires companies to report data on the amount of ratepayer and utility contributions to hardship funds. Shareholders contribute the bulk of utility contributions. The Commission considers ratepayer contributions as contributions from utility employees, ratepayers, and special contributions. Special contributions include monies from formal complaint settlements, overcharge settlements, off-system sales, and special solicitations of business corporations. However, the average voluntary ratepayer contribution per customer does not include special contributions – only voluntary ratepayer contributions. The Commission defines utility contributions as shareholder or utility grants for program administration, outright grants to the funds, and grants that match contributions of ratepayers.

2012-13 Electric Hardship Fund Contributions

Company	Voluntary Ratepayer Contributions	Average Voluntary Ratepayer Contribution per Customer	Utility & Shareholder Contributions
Duquesne	$246,018	$0.47	$450,000
Met-Ed	$126,341	$0.26	$116,522
PECO-Electric	$185,218	$0.10	$400,889
Penelec	$83,248	$0.16	$72,254
Penn Power	$38,950	$0.28	$35,803
PPL	$433,404	$0.36	$815,000
West Penn	$167,985	$0.27	$109,000
Total	**$1,281,164**		**$1,999,468**
Weighted Avg.*		**$0.26**	

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

2012-13 Natural Gas Hardship Fund Contributions

Company	Voluntary Ratepayer Contributions	Average Voluntary Ratepayer Contribution per Customer	Utility & Shareholder Contributions
Columbia	$931,645	$0.51	$195,000
Peoples	$172,223	$0.52	$358,954
Peoples-Equitable	$86,128	$0.35	$200,000
NFG	$44,429	$0.22	$67,000
PECO-Gas	$34,053	$0.05	$59,903
PGW	$742	$0.00	$620,846
UGI-Gas	$72,705	$0.22	$62,540
UGI Penn Natural	$12,263	$0.08	$45,000
Total	**$1,354,188**		**$1,609,243**
Weighted Avg.*		**$0.53**	

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

Hardship Fund Benefits

The USSR requires companies to report data on hardship fund benefits. The Commission defines hardship fund benefits[35] as, "The total number and dollar amount of cash benefits or bill credits." The cumulative total number and dollar amount of the grants disbursed for the program year are reported as of the end of the program year.

Electric Utility Hardship Fund Grant Benefits

Company	Ratepayers Receiving Grants		Average Grant		Total Benefits Disbursed	
	2011-12	**2012-13**	**2011-12**	**2012-13**	**2011-12**	**2012-13**
Duquesne	1,353	2,779	$441	$270	$597,250	$750,000
Met-Ed	434	727	$332	$321	$144,000	$233,672
PECO-Electric	858	734	$383	$499	$328,989	$366,519
Penelec	250	436	$343	$336	$85,662	$146,338
Penn Power	171	183	$337	$320	$57,550	$58,522
PPL	3,600	3,259	$276	$320	$994,996	$1,044,197
West Penn	502	505	$304	$338	$152,454	$170,888
Total	**7,168**	**8,623**			**$2,360,901**	**$2,770,136**
Weighted Avg.*			**$329**	**$321**		

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

[35] 52 Pa. Code § 54.72 and § 62.5

Natural Gas Utility Hardship Fund Grant Benefits

Company	Ratepayers Receiving Grants		Average Grant		Total Benefits Disbursed	
	2011-12	2012-13	2011-12	2012-13	2011-12	2012-13
Columbia	2,884	3,205	$391	$379	$1,127,223	$1,214,215
Peoples	1,674	1,493	$428	$402	$715,654	$600,000
Peoples-Equitable	883	1,028	$393	$389	$347,225	$400,000
NFG	362	389	$229	$235	$82,743	$91,593
PECO-Gas	140	111	$383	$493	$53,556	$54,767
PGW	1,676	1,184	$1,003	$1,076	$1,681,218	$1,273,999
UGI-Gas	833	656	$307	$272	$255,977	$178,752
UGI Penn Natural	1,052	978	$427	$383	$448,885	$375,007
Total	**9,504**	**9,044**			**$4,712,481**	**$4,188,333**
Weighted Avg.*			$496	$463		

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

4. Small Utilities' Universal Service Programs

The USSR has fewer data requirements[36] for small utilities. EDCs with fewer than 60,000 residential customers and NGDCs with fewer than 100,000 residential customers must file universal service plans every three years, but the plans are not subject to the Commission's formal approval process. Instead, the plans are informally reviewed by the Bureau of Consumer Services. In addition to filing their plans with the Commission, small utilities must describe the level of services provided by their plans as well as the expenses associated with the programs.

As a result of the Electricity Generation Customer Choice and Competition Act and the Natural Gas Choice and Competition Act, seven small utilities now have various universal service programs for their low-income customers.

Citizens' Electric (Citizens), Peoples TWP, formerly T.W. Phillips Gas and Oil Company, Valley Energy (Valley), and Wellsboro Electric (Wellsboro) operate hardship funds through the Dollar Energy Fund.

Pike County Power & Light (Pike) administers a variation of a CAP program (New Start) and operates its own hardship fund program (Neighbor Fund Program).

Peoples TWP offers a full-scale CAP program serving approximately 1,113 customers as of Dec. 31, 2013. The company also operates a LIURP program, which completed 46 jobs in 2013.

UGI-Central Penn Gas offers a full-scale CAP program. As of December 2013, the program enrollment was approximately 1,740 customers. UGI-Central Penn Gas also administers a LIURP program, completing 88 jobs in 2013.

UGI Utilites Inc. (UGI-Electric) offers a full-scale CAP program with an enrollment of approximately 1,615 customers. The company operates its own hardship fund and also administers a LIURP program, completing 34 jobs in 2013.

UGI-Central Penn Gas and UGI Utilites Inc. also operate CARES and Hardship Funds (Operation Share).

The small utilities also differ significantly from each other in the total number of residential customers each serves. For example, UGI-Central Penn Gas, UGI Utilities Inc., and Peoples TWP each serve more than 50,000 residential customers. Meanwhile, Citizens', Pike, Wellsboro, and Valley each serve fewer than 6,000 residential customers.

In addition to the utility-sponsored programs, LIHEAP benefits will be available to all low-income households who meet the income guidelines for LIHEAP eligibility.

[36] 52 Pa. Code, Chapter 54, § 54.77 for EDCs and at 52 Pa. Code, Chapter 62, § 62.7 for NGDCs

5. Appendices

Appendix 1 - Grouping of Collection Data Tables

Number of Confirmed Low-Income Electric Customers in Debt

Company	Number of Customers in Debt on an Agreement*	Number of Customers in Debt Not on an Agreement*	Total Number of Customers in Debt*
Duquesne	2,921	4,942	7,863
Met-Ed	15,331	5,008	20,339
PECO-Electric	4,499	11,403	15,902
Penelec	16,250	7,081	23,331
Penn Power	3,648	1,618	5,266
PPL	22,885	46,817	69,702
West Penn	10,269	5,644	15,913
Total	**75,803**	**82,513**	**158,316**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Number of Confirmed Low-Income Natural Gas Customers in Debt

Company	Number of Customers in Debt on an Agreement*	Number of Customers in Debt Not on an Agreement*	Total Number of Customers in Debt*
Columbia	9,224	4,131	13,355
Peoples	5,767	6,052	11,819
Peoples-Equitable	5,000	3,373	8,373
NFG	2,657	1,948	4,605
PECO-Gas	1,288	2,469	3,757
PGW	2,796	6,396	9,192
UGI-Gas	4,255	10,493	14,748
UGI Penn Natural	2,925	5,803	8,728
Total	**33,912**	**40,665**	**74,577**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Confirmed Low-Income Electric Customers in Debt

Company	Percent of Customers in Debt on an Agreement*	Percent of Customers in Debt Not on an Agreement*	Total Percent of Customers in Debt*
Duquesne	5.0%	8.5%	13.5%
Met-Ed	24.9%	8.1%	33.0%
PECO-Electric	2.8%	7.0%	9.7%
Penelec	20.8%	9.1%	29.9%
Penn Power	19.7%	8.7%	28.4%
PPL	13.7%	28.1%	41.9%
West Penn	22.8%	12.5%	35.4%
Total	**12.8%**	**14.0%**	**26.8%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Confirmed Low-Income Natural Gas Customers in Debt

Company	Percent of Customers in Debt on an Agreement*	Percent of Customers in Debt Not on an Agreement*	Total Percent of Customers in Debt*
Columbia	13.6%	6.1%	19.7%
Peoples	9.7%	10.2%	20.0%
Peoples-Equitable	11.6%	7.8%	19.4%
NFG	9.0%	6.6%	15.6%
PECO-Gas	4.0%	7.7%	11.7%
PGW	1.8%	4.1%	5.9%
UGI-Gas	10.8%	26.5%	37.3%
UGI Penn Natural	11.3%	22.3%	33.6%
Total	**7.5%**	**8.9%**	**17.0%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Debt on an Agreement - Confirmed Low-Income Electric Customers

Company	Percent of Dollars Owed – on an Agreement*	Percent of Dollars Owed – Not on an Agreement*
Duquesne	31.6%	68.4%
Met-Ed	89.7%	10.3%
PECO-Electric	24.6%	75.4%
Penelec	88.0%	12.0%
Penn Power	89.0%	11.0%
PPL	21.6%	78.4%
West Penn	80.8%	19.2%
Total	**44.0%**	**56.0%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Percent of Debt on an Agreement - Confirmed Low-Income Natural Gas Customers

Company	Percent of Dollars Owed – on an Agreement*	Percent of Dollars Owed – Not on an Agreement*
Columbia	89.4%	10.6%
Peoples	50.1%	49.9%
Peoples-Equitable	78.9%	21.1%
NFG	57.3%	42.7%
PECO-Gas	25.6%	74.4%
PGW	27.3%	72.7%
UGI-Gas	35.0%	65.0%
UGI Penn Natural	37.9%	62.1%
Total	**49.1%**	**50.9%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Average Arrearage - Confirmed Low-Income Electric Customers

Company	Average Arrearage on an Agreement*	Average Arrearage Not on an Agreement*	Overall Average Arrearage*
Duquesne	$626.97	$803.57	$737.96
Met-Ed	$814.76	$286.03	$684.57
PECO-Electric	$650.44	$785.88	$747.57
Penelec	$737.90	$230.27	$583.83
Penn Power	$777.78	$216.32	$605.27
PPL	$551.55	$979.10	$838.73
West Penn	$491.76	$212.83	$392.83
Total	**$656.29**	**$768.19**	**$714.61**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Average Arrearage - Confirmed Low-Income Natural Gas Customers

Company	Average Arrearage on an Agreement*	Average Arrearage Not on an Agreement*	Overall Average Arrearage*
Columbia	$572.73	$152.24	$442.67
Peoples	$591.74	$562.25	$576.63
Peoples-Equitable	$653.77	$259.51	$494.94
NFG	$462.58	$470.11	$522.96
PECO-Gas	$800.48	$1,211.01	$1,070.27
PGW	$818.58	$954.60	$913.23
UGI-Gas	$395.96	$298.65	$326.73
UGI Penn Natural	$461.01	$380.47	$407.46
Total	**$576.39**	**$498.22**	**$533.76**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

Residential Revenues (Billings) - Electric Customers

Company	Annual Residential Billings
Duquesne	$409,064,999
Met-Ed	$566,265,092
PECO-Electric	$2,024,075,323
Penelec	$472,447,505
Penn Power	$139,707,141
PPL	$1,749,163,222
West Penn	$499,171,103
Total	**$5,859,894,385**

Residential Revenues (Billings) - Natural Gas Customers

Company	Annual Residential Billings
Columbia	$329,063,560
Peoples	$299,632,543
Peoples-Equitable	$246,031,060
NFG	$158,170,597
PECO-Gas	$429,357,880
PGW	$474,805,698
UGI-Gas	$219,614,215
UGI Penn Natural	$166,532,193
Total	**$2,323,207,746**

Residential Revenues (Billings) - Confirmed Low-Income Electric Customers

Company	Annual Residential Billings
Duquesne	$61,238,026
Met-Ed	$84,314,156
PECO-Electric	$114,994,197
Penelec	$89,379,373
Penn Power	$21,402,507
PPL	$297,086,798
West Penn	$51,024,384
Total	**$719,439,441**

Residential Revenues (Billings) - Confirmed Low-Income Natural Gas Customers

Company	Annual Residential Billings
Columbia	$55,816,737
Peoples	$77,904,461
Peoples-Equitable	$37,712,551
NFG	$19,421,951
PECO-Gas	$17,108,246
PGW	$121,666,621
UGI-Gas	$31,883,003
UGI Penn Natural	$29,288,114
Total	**$390,801,684**

Terminations - Residential Electric Customers

Company	2011 Terminations	2012 Terminations	2013 Terminations	Change 2011-13
Duquesne	22,927	23,533	25,649	11.9%
Met-Ed	18,169	17,995	23,672	30.3%
PECO-Electric	80,967	73,344	83,185	2.7%
Penelec	17,513	13,747	20,544	17.3%
Penn Power	3,622	3,514	4,999	38.0%
PPL	33,641	38,303	47,759	42.0%
West Penn	15,351	11,092	13,904	-9.4%
Total	**192,190**	**181,528**	**219,712**	**14.3%**

Terminations - Residential Natural Gas Customers

Company	2011 Terminations	2012 Terminations	2013 Terminations	Change 2011-13
Columbia	9,650	11,321	12,030	24.7%
Peoples	3,696	6,601	7,229	95.6%
Peoples-Equitable	10,471	8,394	8,507	-18.8%
NFG	9,472	8,347	9,576	1.1%
PECO-Gas	23,630	20,411	22,054	-6.7%
PGW	28,868	25,507	28,497	-1.3%
UGI-Gas	11,206	8,434	9,055	-19.2%
UGI Penn Natural	6,967	5,403	6,214	-10.8%
Total	**103,960**	**94,418**	**103,162**	**-0.8%**

Exhibit JH-8

Number of Residential Electric Customers in Debt

Company	2011 Total Number of Customers in Debt*	2012 Total Number of Customers in Debt*	2013 Total Number of Customers in Debt*	Change 2011-13
Duquesne	21,589	21,965	21,956	1.7%
Met-Ed	54,064	46,622	44,990	-16.8%
PECO-Electric**	113,335	118,675	120,703	6.5%
Penelec	54,370	46,649	45,989	-15.4%
Penn Power	13,018	10,575	10,706	-17.8%
PPL	144,839	134,823	134,751	-7.0%
West Penn	78,290	51,529	43,765	-44.1%
Total	**479,505**	**430,838**	**422,860**	**11.8%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 142,434 has been revised to exclude CAP, consistent with reporting requirements.

Number of Residential Natural Gas Customers in Debt

Company	2011 Total Number of Customers in Debt*	2012 Total Number of Customers in Debt*	2013 Total Number of Customers in Debt*	Change 2011-13
Columbia	22,620	36,940	30,157	33.3%
Peoples	36,587	32,701	30,099	-17.7%
Peoples-Equitable	16,849	17,468	18,826	11.7%
NFG	9,481	9,744	9,811	3.5%
PECO-Gas**	30,309	30,988	31,679	4.5%
PGW	86,413	61,640	77,839	-9.9%
UGI-Gas	25,055	25,903	29,534	17.9%
UGI Penn Natural	12,903	13,209	14,908	15.5%
Total	**240,217**	**228,593**	**242,853**	**1.1%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 35,039 has been revised to exclude CAP, consistent with reporting requirements.

Exhibit JH-8

Dollars in Debt - Residential Electric Customers

Company	2011 Total Dollars in Debt*	2012 Total Dollars in Debt*	2013 Total Dollars in Debt*	Change 2011-13
Duquesne	$10,995,577	$11,004,856	$11,271,501	2.5%
Met-Ed	$30,213,223	$27,405,440	$23,740,747	-21.4%
PECO-Electric**	$51,523,862	$51,297,270	$53,030,783	2.9%
Penelec	$24,147,917	$23,715,969	$21,016,356	-13.0%
Penn Power	$7,325,332	$5,899,155	$5,015,168	-31.5%
PPL	$81,870,581	$79,988,700	$83,490,365	2.0%
West Penn	$9,067,548	$10,589,845	$12,424,966	37.0%
Total	**$215,144,040**	**$209,901,235**	**$209,989,886**	**-2.4%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of $76,791,682 has been revised to exclude CAP, consistent with reporting requirements.

Dollars in Debt - Residential Natural Gas Customers

Company	2011 Total Dollars in Debt*	2012 Total Dollars in Debt*	2013 Total Dollars in Debt*	Change 2011-13
Columbia	$8,974,795	$8,569,783	$10,343,332	15.2%
Peoples	$15,380,911	$15,012,948	$11,787,163	-23.4%
Peoples-Equitable	$6,947,492	$6,047,220	$6,593,921	-5.1%
NFG	$3,691,715	$3,759,477	$3,489,351	-5.5%
PECO-Gas**	$21,255,291	$18,670,937	$18,707,389	-12.0%
PGW	$48,126,888	$36,314,051	$46,967,191	-2.4%
UGI-Gas	$6,795,857	$5,595,669	$7,184,309	5.7%
UGI Penn Natural	$4,800,701	$3,925,932	$4,982,221	3.8%
Total	**$115,973,650**	**$97,896,015**	**$110,054,877**	**-5.1%**

* See Appendix 2 for a chart showing the different methods companies use to determine overdue accounts and how they compare to the preferred method (30 days overdue). See Appendix 3 for the methods companies use to determine when an account is removed from active status after termination of service or discontinuance of service.

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of $21,441,745 has been revised to exclude CAP, consistent with reporting requirements.

Gross Write-Offs Ratio - Residential Electric Customers

Company	2011 Gross Write-Offs Ratio*	2012 Gross Write-Offs Ratio*	2013 Gross Write-Offs Ratio*	Change 2011-13
Duquesne	1.2%	1.4%	1.3%	8.3%
Met-Ed	1.9%	2.4%	1.9%	0.0%
PECO-Electric	1.5%	2.0%	1.9%	26.7%
Penelec	1.8%	2.1%	1.9%	5.6%
Penn Power	1.8%	1.7%	1.3%	-27.8%
PPL	2.7%	3.2%	3.1%	14.8%
West Penn	1.0%	1.3%	1.2%	20.0%
Total	**1.8%**	**2.2%**	**2.1%**	**16.7%**

*Does not include CAP Credits or Arrearage Forgiveness.

Gross Write-Offs Ratio - Residential Natural Gas Customers

Company	2011 Gross Write-Offs Ratio*	2012 Gross Write-Offs Ratio*	2013 Gross Write-Offs Ratio*	Change 2011-13
Columbia	2.8%	2.8%	2.0%	-28.6%
Peoples	1.8%	0.3%	3.6%	100.0%
Peoples-Equitable	2.1%	1.9%	1.9%	-9.5%
NFG	2.0%	2.6%	2.2%	10.0%
PECO-Gas	1.0%	0.7%	0.5%	-50.0%
PGW	8.0%	9.1%	10.4%	30.0%
UGI-Gas	2.3%	2.3%	2.2%	-4.3%
UGI Penn Natural	2.1%	1.8%	1.6%	-23.8%
Total	**3.2%**	**3.2%**	**3.7%**	**15.6%**

*Does not include CAP Credits or Arrearage Forgiveness.

Exhibit JH-8

Percent of Revenues (Billings) in Debt - Residential Electric Customers

Company	2011	2012	2013	Change 2011-13
Duquesne	2.1%	2.3%	2.8%	33.3%
Met-Ed	4.1%	4.6%	4.2%	2.4%
PECO-Electric**	2.4%	2.5%	2.6%	8.3%
Penelec	4.0%	4.6%	4.4%	10.0%
Penn Power	4.2%	3.9%	3.6%	-14.3%
PPL	4.4%	5.0%	4.8%	9.1%
West Penn	1.3%	2.0%	2.5%	92.3%
Total	**3.2%**	**3.6%**	**3.6%**	**12.5%**

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 3.8% has been revised to exclude CAP, consistent with reporting requirements.

Percent of Revenues (Billings) in Debt - Residential Natural Gas Customers

Company	2011	2012	2013	Change 2011-13
Columbia	2.6%	3.2%	3.1%	19.2%
Peoples	6.2%	6.0%	3.9%	-37.1%
Peoples-Equitable	2.8%	2.9%	2.7%	-3.6%
NFG	2.0%	2.5%	2.2%	10.0%
PECO-Gas**	4.9%	5.0%	4.4%	-10.2%
PGW	9.6%	8.4%	9.9%	3.1%
UGI-Gas	2.7%	2.8%	3.3%	22.2%
UGI Penn Natural	2.8%	2.7%	3.0%	7.1%
Total	**4.9%**	**4.8%**	**4.7%**	**-4.1%**

** PECO data in the 2012 Universal Service Program & Collections Performance report included CAP customers. The previous 2012 figure of 5.7% has been revised to exclude CAP, consistent with reporting requirements.

Appendix 2 - When is an Account Considered to be Overdue?

Company	When is Day Zero (0)	How Many Days Overdue	Days of Variance from BCS Interpretation*
Duquesne	Bill Due Date	30 Days	0 Days
Met-Ed and Penelec	Bill Due Date	30 Days	0 Days
PECO-Electric	Bill Transmittal Date	30 Days	20 Days Sooner
Penn Power	Bill Due Date	30 Days	0 Days
PPL	Bill Transmittal Date	30 Days	20 Days Sooner
West Penn	Bill Due Date	10 Days	20 Days Sooner
Columbia	Bill Due Date	30 Days	0 Days
Peoples	Bill Transmittal Date	30 Days	20 Days Sooner
Peoples-Equitable	Bill Due Date	30 Days	0 Days
NFG	Bill Rendition Date**	60 Days	9 Days Later
PECO-Gas	Bill Transmittal Date	30 Days	20 Days Sooner
PGW	Bill Transmittal Date	30 Days	20 Days Sooner
UGI-Gas	Bill Due Date	30 Days	0 Days
UGI Penn Natural	Bill Due Date	30 Days	0 Days

*The PUC considers day zero to be the bill due date and the applicable regulations require companies to report arrearages beginning at 30 days overdue.

**Bill Rendition Date is one day prior to the Bill Transmittal Date.

Appendix 3 - When Does an Account Move from Active to Inactive Status?

Company	After an Account is Terminated	After an Account is Discontinued
Duquesne	7 Days after Termination Date	3 to 5 Days after Discontinuance
Met-Ed and Penelec	10 Days after Termination Date	Same Day as Discontinuance
PECO-Electric	30 to 32 Days after Termination Date	Same Day as Discontinuance
Penn Power	10 Days after Termination Date	Same Day as Discontinuance
PPL	5 to 8 Days after Termination Date	Bill Transmittal Date
West Penn	10 Days after Termination Date	0 to 1 Day after Final Bill Transmittal Date
Columbia	5 to 7 Days after Termination Date	Same Day as Discontinuance
Peoples	10 Days after Termination Date	10 Days after Discontinuance
Peoples-Equitable	3 Days after Termination Date	3 Days after Discontinuance
NFG	Same Day as Termination Date	Same Day as Discontinuance
PECO-Gas	30 to 32 Days after Termination Date	Same Day as Discontinuance
PGW	0 to 30 Days after Termination Date	0 to 1 Day after Final Bill Transmittal Date
UGI-Gas	Same Day as Termination Date	Same Day as Discontinuance
UGI Penn Natural	Same Day as Termination Date	Same Day as Discontinuance

Appendix 4 – 2013 and 2014 Federal Poverty Guidelines

2013 Annual Federal Poverty Income Guidelines*				
Size of Household	**0-50 percent of Poverty**	**51-100 percent of Poverty**	**101-150 percent of Poverty**	**151-200 percent of Poverty**
1	$5,745	$11,490	$17,235	$22,980
2	$7,755	$15,510	$23,265	$31,020
3	$9,765	$19,530	$29,295	$39,060
4	$11,775	$23,550	$35,325	$47,100
5	$13,785	$27,570	$41,355	$55,140
6	$15,795	$31,590	$47,385	$63,180
7	$17,805	$35,610	$53,415	$71,220
8	$19,815	$39,630	$59,445	$79,260
For each additional person, add	$2,010	$4,020	$6,030	$8,040

* Income reflects upper limit of the poverty guideline for each column.
Effective: January 24, 2013. SOURCE: Federal Register, Vol. 78, January 24, 2013, pp. 5182-5183.

2014 Annual Federal Poverty Income Guidelines*				
Size of Household	**0-50 percent of Poverty**	**51-100 percent of Poverty**	**101-150 percent of Poverty**	**151-200 percent of Poverty**
1	$5,835	$11,670	$17,505	$23,340
2	$7,865	$15,730	$23,595	$31,460
3	$9,895	$19,790	$29,685	$39,580
4	$11,925	$23,850	$35,775	$47,700
5	$13,955	$27,910	$41,865	$55,820
6	$15,985	$31,970	$47,955	$63,940
7	$18,015	$36,030	$54,045	$72,060
8	$20,045	$40,090	$60,135	$80,180
For each additional person, add	$2,030	$4,060	$6,090	$8,120

* Income reflects upper limit of the poverty guideline for each column.
Effective: January 22, 2014. SOURCE: Federal Register, Vol. 79, January 22, 2014, pp. 3593-3594.

Appendix 5 - Source of Income for Universal Service Participants

Source of Income for Electric Universal Service Participants

	LIURP	CAP	Hardship Fund
Employment	34.4%	24.3%	40.4%
Public Assistance	3.6%	5.5%	4.3%
Pension or Retirement	11.0%	18.3%	13.8%
Unemployment Compensation	21.7%	4.8%	5.7%
Disability	16.8%	18.7%	13.8%
Other	12.5%	28.4%	22.0%

Source of Income for Natural Gas Universal Service Participants

	LIURP	CAP	Hardship Fund
Employment	27.1%	28.6%	45.0%
Public Assistance	4.4%	7.4%	3.0%
Pension or Retirement	28.8%	24.9%	12.5%
Unemployment Compensation	12.4%	5.0%	6.2%
Disability	21.4%	23.3%	20.5%
Other	6.0%	10.8%	13.0%

Appendix 6 - Percent of Spending by CAP Component

Percent of Electric Total CAP Spending by CAP Component

Company	2012			2013		
	Admin Costs	CAP Credits	Arrearage Forgiveness	Admin Costs	CAP Credits	Arrearage Forgiveness
Duquesne	7%	77%	15%	8%	76%	17%
Met-Ed	5%	81%	13%	10%	78%	13%
PECO-Electric	3%	85%	13%	3%	85%	12%
Penelec	6%	83%	11%	11%	79%	10%
Penn Power	5%	82%	13%	11%	78%	11%
PPL	5%	59%	36%	4%	66%	30%
West Penn	8%	59%	34%	5%	64%	31%
Weighted Avg.*	**4%**	**77%**	**18%**	**6%**	**77%**	**17%**

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

Percent of Natural Gas Total CAP Spending by CAP Component

Company	2012			2013		
	Admin Costs	CAP Credits	Arrearage Forgiveness	Admin Costs	CAP Credits	Arrearage Forgiveness
Columbia	15%	84%	1%	7%	89%	4%
Peoples	15%	64%	21%	10%	68%	22%
Peoples-Equitable	9%	85%	6%	8%	87%	5%
NFG	9%	72%	19%	13%	72%	15%
PECO-Gas	9%	73%	18%	8%	79%	13%
PGW	1%	88%	11%	2%	89%	9%
UGI-Gas	7%	75%	18%	6%	70%	24%
UGI Penn Natural	6%	78%	16%	6%	68%	26%
Weighted Avg.*	**5%**	**84%**	**11%**	**4%**	**86%**	**10%**

*Weighted Average is based on industry totals and does not represent an average of the participation rates shown in the table.

Appendix 7 - Instructions to Access Universal Service Plans and Evaluations on PUC Website

- Go to the PUC website at: www.puc.pa.gov. On the PUC's website, locate and click on the "Consumer Info" tab on the headings bar.
- On the right side of the page, locate and click on "Consumer Information on Energy Efficiency, Assistance Programs, Safety, Shopping, & More" in the column of options. Click "Read More" to access the page.
- Under the header titled "Energy Assistance Information," click on "Energy Assistance" to access the Energy Assistance Programs page.
- Under the header "Universal Service Plans & Evaluations" you will find the most current Universal Service Plan and Evaluation for each major EDC and NGDC.

Appendix 8 - Universal Service Programs 2013 Spending Levels & Cost Recovery Mechanisms

Company	Cost Recovery Mechanism[1]	Annual CAP Spending	Annual Total Universal Service Spending[2]	Universal Service Spending Assessed on Residential Customers	Average Number of Residential Customers	Average Annual Universal Service Spending per Residential Customer
Duquesne	Base Rates	$16,549,705	$18,382,533	100%	526,817	$34.89
Met-Ed	USC Rider-Annual	$22,984,906	$26,345,613	100%	488,375	$53.95
PECO-Electric	Base Rates & Univ. Service Fund Charge	$91,708,724	$98,547,978	100%	1,421,426	$69.33
Penelec	USC Rider-Annual	$25,303,288	$29,308,073	100%	504,543	$58.09
Penn Power	USC Rider-Annual	$6,116,965	$7,651,533	100%	141,147	$54.21
PPL	US Rider-Annual	$55,223,019	$63,456,467	100%	1,218,734	$52.07
West Penn	Base Rates	$10,768,235	$13,444,879	100%	619,531	$21.70
EDC Total		**$228,654,842**	**$257,137,076**		**4,920,573**	
EDC Weighted Avg.*						**$52.26**
Columbia	USP Rider	$13,272,158	$18,031,209	100%	384,213	$46.93
Peoples	Rider F	$8,227,588	$9,484,832	100%	330,123	$28.73
Peoples-Equitable	Rider D	$7,090,722	$8,243,335	100%	242,632	$33.97
NFG	Rider F	$1,838,472	$3,375,672	100%	198,763	$16.98
PECO-Gas	Base Rates & Univ. Service Fund Charge	$5,219,029	$7,654,205	100%	456,331	$16.77
PGW	USEC Surcharge	$77,281,237	$86,003,672[3]	75%[4]	468,943	$183.40
UGI-Gas	Rider LISHP	$3,176,112	$3,688,185	100%	324,576	$11.36
UGI Penn Natural	Rider E	$2,852,339	$3,843,399	100%	149,097	$25.78
NGDC Total		**$118,957,657**	**$140,324,509**		**2,554,678**	
NGDC Weighted Avg.*						**$54.93**

*Weighted Averages are based on industry totals and do not represent an average of the participation rates shown in the tables.

[1]Riders and USEC/USFM Surcharge are charges for CAP costs, in addition to base rates, that are adjusted quarterly or annually.
[2]Universal Service costs include CAP costs, LIURP costs and CARES costs.
[3] PGW universal service costs do not include Senior Citizen Discount (SCD) costs. Because income is not an eligibility criterion, the SCD does not meet the definition of universal service.
[4] PGW CAP and LIURP 2013 costs were assessed in the following manner: residential (74 percent), commercial (21 percent), industrial (2 percent), municipal service (2 percent) and Philadelphia Housing Authority (PHA) (1 percent).

Exhibit JH-8

PENNSYLVANIA PUC

PUBLIC UTILITY COMMISSION

EXHIBIT JH-14

Iowa Utilities Board
Residential Customer Statistics
Totals for: October 2014

Category	September 2014*	October 2014	% Change Sep - Oct	October 2013*	% Change 2013-2014
Total Accounts	1,846,958	1,851,351	0.24%	1,841,443	0.54%
Total Accounts Past Due	260,736	262,505	0.68%	260,663	0.71%
E.A. Eligible Accounts	95,153	48,598	-48.93%	49,055	-0.93%
E.A. Eligible Accounts w/Past Due Balance	32,693	13,718	-58.04%	13,815	-0.70%
Revenue of Past Due Accounts	$ 30,730,685	26,834,552	-12.68%	$ 28,963,610	-7.35%
Revenue of Past Due E.A. Eligible Accts	$ 4,649,167	2,950,173	-36.54%	$ 3,147,479	-6.27%
Disconnection Notices Issued	92,990	95,643	2.85%	99,023	-3.41%
Disconnection Notices to E.A. Eligibles	8,267	4,409	-46.67%	4,182	5.43%
Involuntary Disconnections	6,628	5,988	-9.66%	4,178	43.32%
Reconnections	4,669	4,930	5.59%	3,339	47.65%
Accounts Determined Uncollectible	6,113	6,368	4.17%	6,686	-4.76%
Uncollectible E.A. Eligible Accounts	1,414	749	-47.03%	940	-20.32%

* Beginning in October 2014, Amana elected to cease filing monthly residential customer statistics. As a non-rate-regulated electric utility, Amana is not subject to mandatory reporting under 199 IAC 20.2(5)"j", but had been filing reports on a voluntary basis. To allow for a more useful comparison going forward, monthly totals for October 2013 and September 2014 have been adjusted to remove Amana's reported figures.

Iowa Utilities Board
Residential Customer Statistics
Breakdown by Company for: October 2014

Category	Amana* (Electric Only)	Linn County REC (Electric Only)	Black Hills Energy f/k/a Aquila (Gas Only)	Liberty Energy f/k/a Atmos (Gas Only)
Total Accounts	Please see footnote on page 1	27,839	136,154	3,924
Total Accounts Past Due		1,189	15,363	104
E.A. Eligible Accounts		271	3,293	114
E.A. Eligible Accounts w/Past Due Balance		97	212	24
Revenue of Past Due Accounts		$ 524,238	$ 178,963	$ 17,836
Revenue of Past Due E.A. Eligible Accts		$ 25,298	$ 10,024	$ 5,386
Disconnection Notices Issued		774	4,053	104
Disconnection Notices to E.A. Eligibles**		72	212	0
Involuntary Disconnections		56	797	16
Reconnections		47	419	58
Accounts Determined Uncollectible		57	634	0
Uncollectible E.A. Eligible Accounts		0	71	0

**Companies received notice from agency that customers were eligible for energy assistance after disconnect notice prepared and sent.

Iowa Utilities Board
Residential Customer Statistics
Breakdown by Company for: October 2014

Category	IP&L (Electric)	IP&L (Gas)	MidAmerican (Electric)	MidAmerican (Gas)
Total Accounts	407,472	197,931	562,159	515,872
Total Accounts Past Due	72,370	33,689	72,648	67,142
E.A. Eligible Accounts	16,165	12,218	8,963	7,574
E.A. Eligible Accounts w/Past Due Balance	5,339	4,045	2,048	1,953
Revenue of Past Due Accounts	$ 12,489,046	$ 3,078,900	$ 8,569,063	$ 1,976,506
Revenue of Past Due E.A. Eligible Accts	$ 1,399,447	$ 1,159,036	$ 284,513	$ 66,469
Disconnection Notices Issued	41,403	16,428	17,739	15,142
Disconnection Notices to E.A. Eligibles**	1,780	1,348	528	469
Involuntary Disconnections	1,209	96	3,137	677
Reconnections	968	191	2,710	537
Accounts Determined Uncollectible	1,082	845	1,989	1,761
Uncollectible E.A. Eligible Accounts	0	0	359	319

**Companies received notice from agency that customers were eligible for energy assistance after disconnect notice prepared and sent.