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PUBLIC SERVICE COMMISSION

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June 30, 2014

Re: CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES
Case No. 2012-00428

Dear Mr. DeRouen:

Enclosed please find and accept for filing the original and fourteen copies of the Joint Report of Atmos Energy Corporation, Big Rivers Electric Corporation, Big Sandy Rural Electric Cooperative Corporation, Blue Grass Energy Cooperative Corporation, Clark Energy Cooperative, Inc., Columbia Gas of Kentucky, Inc., Cumberland Valley Electric, Delta Natural Gas Company, Inc., Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Farmers Rural Electric Cooperative Corporation, Fleming-Mason Energy Cooperative, Inter-County Energy Cooperative Corporation, Jackson Energy Cooperative Corporation, Jackson Purchase Energy Corporation, Kenergy Corp., Kentucky Power Company, Kentucky Utilities Company, Licking Valley Rural Electric Cooperative Corporation, Louisville Gas and Electric Company, Meade County Rural Electric Cooperative Corporation, Nolin Rural Electric Cooperative Corporation, Owen Electric Cooperative, Inc., Salt River Electric Cooperative Corporation, Shelby Energy Cooperative, Inc., South Kentucky Rural Electric Cooperative Corporation, and Taylor County Rural Electric Cooperative Corporation (collectively, the "Joint Utilities"), with comments by the Attorney General of the Commonwealth of Kentucky by and through his office of Rate Intervention ("AG") and the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"), as per the Report Development Schedule presented at the August 23, 2013 Informal Conference regarding the above-referenced case. The signature pages for each party are attached to this letter.

On July 17, 2013, the Kentucky Public Service Commission ("Commission") issued an order directing the Joint Utilities, AG, and CAC to examine collaboratively nine topics related to smart technologies and their deployment in Kentucky: customer privacy, opt-out provisions, customer education (including health-related education), dynamic pricing, Automated Meter Reading ("AMR") and Advanced Metering Infrastructure ("AMI") deployment (including prepaid meters and remote disconnections)[1], cyber-security, cost recovery for smart-technology deployments and obsolete equipment, how natural gas companies might participate in the electric smart grid, and whether the Commission should adopt the Smart Grid Investment and Information Standards proposed in the federal Energy Independence and Security Act of 2007 ("EISA 2007"). This report is the final product of that collaborative effort, which has spanned nearly a year.

Should you have any questions, please contact me at your convenience.

Sincerely,

Rick E. Lovekamp

c: Parties of Record

[1] This section has been renamed "Distribution Smart-Grid Components."

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Respectfully submitted,

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My signature indicates Salt River Electric Cooperative Corporation's approval of the report in so far as this purports to state the Salt River Electric Cooperative's position.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES	)))	CASE NO. 2012-00428

REPORT OF THE JOINT UTILITIES:
ATMOS ENERGY CORPORATION, BIG RIVERS ELECTRIC CORPORATION, BIG SANDY RURAL ELECTRIC COOPERATIVE CORPORATION, BLUE GRASS ENERGY COOPERATIVE CORPORATION, CLARK ENERGY COOPERATIVE, INC., COLUMBIA GAS OF KENTUCKY, INC., CUMBERLAND VALLEY ELECTRIC, DELTA NATURAL GAS COMPANY, INC., DUKE ENERGY KENTUCKY, INC., EAST KENTUCKY POWER COOPERATIVE, INC., FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION, FLEMING-MASON ENERGY COOPERATIVE, INTER-COUNTY ENERGY COOPERATIVE CORPORATION, JACKSON ENERGY COOPERATIVE CORPORATION, JACKSON PURCHASE ENERGY CORPORATION, KENERGY CORP., KENTUCKY POWER COMPANY, KENTUCKY UTILITIES COMPANY, LICKING VALLEY RURAL ELECTRIC COOPERATIVE CORPORATION, LOUISVILLE GAS AND ELECTRIC COMPANY, MEADE COUNTY RURAL ELECTRIC COOPERATIVE CORPORATION, NOLIN RURAL ELECTRIC COOPERATIVE CORPORATION, OWEN ELECTRIC COOPERATIVE, INC., SALT RIVER ELECTRIC COOPERATIVE CORPORATION, SHELBY ENERGY COOPERATIVE, INC., SOUTH KENTUCKY RURAL ELECTRIC COOPERATIVE CORPORATION, AND TAYLOR COUNTY RURAL ELECTRIC COOPERATIVE CORPORATION

WITH COMMENTS BY:
THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY BY AND THROUGH HIS OFFICE OF RATE INTERVENTION
AND
THE COMMUNITY ACTION COUNCIL FOR LEXINGTON-FAYETTE, BOURBON, HARRISON AND NICHOLAS COUNTIES, INC.

Filed: June 30, 2014

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Executive Summary

On July 17, 2013, the Kentucky Public Service Commission ("Commission") issued an order directing the Joint Utilities,[1] the Attorney General of the Commonwealth of Kentucky by and through His Office of Rate Intervention ("AG"), and the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC") to examine collaboratively nine topics related to smart technologies and their deployment in Kentucky: customer privacy, opt-out provisions, customer education (including health-related education), dynamic pricing, Automated Meter Reading ("AMR") and Advanced Metering Infrastructure ("AMI") deployment (including prepaid meters and remote disconnections),[2] cyber-security, cost recovery for smart-technology deployments and obsolete equipment, how natural gas companies might participate in the electric smart grid, and whether the Commission should adopt the Smart Grid Investment and Information Standards proposed in the federal Energy Independence and Security Act of 2007 ("EISA 2007").[3] This report is the final product of that collaborative effort, which has spanned nearly a year.

The sections that follow provide detailed discussions of the nine topics the Commission directed the Joint Utilities, AG, and CAC to address, including useful background information and analytical frameworks for considering these issues. As the Joint Utilities, AG, and CAC anticipated before beginning their collaborative effort, they reached different levels of consensus on different topics:[4]

- **Customer Privacy**
    - Joint Utilities: Customer privacy is an important issue independent of smart-technology considerations. But there are already federal and state legal protections in place concerning customer information in utilities' possession, and government and industry groups are working to develop even more robust voluntary standards for utilities to consider. Moreover, Kentucky's utilities have already gone beyond the legal requirements in place today to ensure that only appropriate use is made of customer information. Therefore, Joint Utilities conclude that a new mandatory customer-privacy standard is not necessary at this time, including the customer data provisions of the EISA 2007 Smart-Grid Information Standard. Instead, the Joint Utilities propose a list of terms to define and substantive items for utilities to consider when reviewing customer-privacy policies and practices, which the

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[1] Except as otherwise noted at various points herein, "Joint Utilities" includes all the parties named as Joint Utilities on the cover page of this report and in Appendix A.
[2] The Joint Utilities have renamed this section "Distribution Smart-Grid Components."
[3] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 7-8 (July 17, 2013).
[4] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Joint Comments at 7 (May 20, 2013).

Commission may find useful when addressing smart-grid or other customer-privacy-related utility proposals.

- AG: The Attorney General recommends that the Commission adopt a state-wide mandated customer privacy standard containing both the ability for the PSC to issue significant civil penalties for non-compliance and an opt-in policy for any disclosure of consumer information a utility wishes to make.

- CAC: CAC supports utilities' efforts to maintain customer privacy. Aggregated customer information is often helpful to CAC in its effort to provide assistance to low-income customers in paying their bills and in its mission as an advocate for low-income customers. Information should be readily available to CAC for these purposes and in regulatory proceedings. Utilities benefit from this low-income assistance. The utilities should absorb the costs of providing this information.

- **Opt-Out Provisions**

  - Joint Utilities: Customer concerns over purported health and privacy impacts of smart meters have caused some states to require utilities to offer opt-out provisions from smart-meter deployments. But requiring utilities to offer opt-outs from smart-meter deployments has potentially significant cost and operational impacts for utilities and customers, both those who choose to opt out and those who do not. Determining how to allocate the direct and indirect costs of opt-out provisions among customers who opt out and those who do not is also a challenging issue. Therefore, the Joint Utilities agree the cost impacts and reduced operational capabilities (to both opting-out customers and all other customers) of requiring opt-out arrangements are not generally beneficial on the whole. Moreover, Duke, AEP, and several cooperatives have considerable experience with meter deployments, and have found ways to work directly with customers through customer education (see below) to accomplish overall program goals without opt-out requirements. Instead, a case-by-case approach using some or all of the analytical framework this section presents may be an appropriate approach to evaluate opt-outs.

  - AG: Both technical and informational opt-out should be available to customers, where infrastructure allows.

  - CAC: If a utility does offer opt-out alternatives, customers should not be penalized for choosing to opt-out.

EXECUTIVE SUMMARY

- **Customer Education**
  - Joint Utilities: Customer education is likely to increase the success of any smart-meter deployment. By ensuring customers understand the benefits and features of the smart technology being deployed, a deploying utility can help minimize customer concerns and objections while increasing the likelihood that projected benefits will be realized as customers engage with the technology and use it to improve their energy consumption. Therefore, the Joint Utilities recommend that each utility deploying smart meters consider using some of the customer-education topics (e.g., privacy issues) and channels (e.g., mass media) addressed in this section.
  - AG: The Attorney General has no additional comments with regard to this chapter.
  - CAC: Customer education should be mandatory as smart meters are deployed.
- **Dynamic Pricing**
  - Joint Utilities: The Joint Utilities' collective experience is that dynamic pricing for residential customers tends to have low participation, and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those experiences, the Joint Utilities agree that a utility should consider some or all of the issues discussed in this section (e.g., rate structures and contract terms) before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Utilities further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.
  - AG: The Commission should never require mandatory residential TOU rates; rather, such rates should always be no more than an option for residential ratepayers.
  - CAC: Low-income advocates are especially concerned about the potential impact on low-income customers who typically do not fully understand the complexities of dynamic pricing or lack the technology to fully take advantage of such rates, which could inadvertently result in higher bills for those customers. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for

residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

- **Distribution Smart-Grid Components**

    - Joint Utilities: Although distribution smart-grid components can provide benefits to customers and add value to utilities' distribution systems, there are a number of items utilities might consider before investing in such systems, including items related to technological obsolescence, prepaid metering, and remote connection and disconnection of utility service, all of which can impact customers. But adding another layer of regulation, i.e., the EISA 2007 Smart-Grid Investment Standard, to the Commission's already robust oversight authority is not necessary to ensure utilities make only prudent investments; rather, the Commission's existing authority concerning base rates, Certificates of Public Convenience and Necessity and Construction Work Plans (collectively "CPCNs"), and non-base-rate recovery mechanisms is sufficient to protect customers while maintaining regulatory efficiency.

    - AG: The Attorney General has no additional comments with regard to this chapter.

    - CAC: No comments.

- **Cyber-Security**

    - Joint Utilities: Utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks; on the issue of cyber-security, all stakeholders' interests and incentives are aligned. But existing mandatory and voluntary cyber-security standards, frameworks, and guidelines are sufficient; adding such regulations or rules at the state level may serve to weaken rather than strengthen utilities' ability to thwart cyber-attacks by slowing their ability to adapt to the ever-changing threat. The cyber-security focus should be on a utility's ability to evolve with emerging threats, not on its compliance with cyber-security standards based on legacy threat profiles. A mature, effective cyber-security process is one that is continuously evolving based on emerging threat intelligence and threat vectors or actions. Therefore, additional regulations or requirements at the state level are not necessary or advisable.

EXECUTIVE SUMMARY

- AG: The Attorney General recommends that the Commission require all jurisdictional utility companies to not only comply with the mandatory and voluntary standards, guidelines and resources cited in the majority report, but to exercise the best foreseeable measures possible to secure their companies' cyber-security.

- CAC: Utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks.

- **Cost Recovery**

  - Joint Utilities: Because utilities may and are deploying smart technologies under different circumstances, in different ways, at different paces, and to different extents, there cannot be a one-size-fits-all approach to cost recovery for, or review of, smart-technology deployments. Instead, to encourage the most economically rational yet innovative uses and deployments of smart technologies, the Joint Utilities believe: (1) all forms of cost recovery should be available for utilities to consider and propose to the Commission, including traditional base rates, existing cost-recovery mechanisms (e.g., demand-side management ("DSM") riders), and new riders or surcharge mechanisms; (2) utilities proposing smart-technology deployments that will necessitate retiring existing utility assets with unrecovered book life should take the cost of those retirements into account in their cost-benefit analyses and be able to recover that cost if the deployment is prudent; and (3) additional smart-grid-specific review proceedings or criteria are unnecessary for smart-grid deployments because existing cost-recovery and other review proceedings and mechanisms are sufficient, including CPCN proceedings and various kinds of rate proceedings. The Joint Utilities therefore continue to oppose the imposition of the EISA 2007 Smart-Grid Investment Standard or any derivative thereof.

  - AG: The Attorney General does not oppose the economical and cost-effective investment and use of smart technologies, but reserves his position subject to a case-by-case review of cost recovery mechanisms. The Attorney General has no additional comments with regard to this chapter.

  - CAC: No comments.

EXECUTIVE SUMMARY

- **How Natural Gas Companies Might Participate in the Electric Smart Grid**

  - Joint Utilities: Kentucky's natural-gas local distribution companies ("LDCs") have in some ways pioneered deploying automated and smart technologies among utility operations, having deployed Supervisory Control and Data Acquisition ("SCADA") in their distribution systems and AMR in meter reading for many years. Having already achieved the efficiencies associated with those technologies, though, means that LDCs and their customers may have less to gain from further smart-technology deployments. Also, there are a number of benefits or efficiencies that electric smart technologies might provide or enable that would not benefit LDCs, such as time-of-use or dynamic pricing and remote-reconnection capabilities. Nonetheless, the LDCs among the Joint Utilities remain committed to seeking economical means of participating in the electric smart grid or developing an independent gas smart grid.

  - AG: The Attorney General has no additional comments with regard to this chapter.

  - CAC: No comments.

- **EISA 2007 Smart Grid Information and Investment Standards**

  - Joint Utilities: Smart technologies, both customer-facing and grid-deployed, hold much promise for maintaining and increasing the quality of utility service while reducing costs. But each utility must have the flexibility to propose solutions that are prudent for its customers, solutions that will vary depending on geography, customer density, existing system constraints and resources, and a host of other factors. Also, smart technologies continue to advance and mature at a rapid pace, and there is no industry consensus about which technologies every utility must deploy. Therefore, the Joint Utilities continue to hold the position they expressed in their May 20, 2013 Joint Comments in this proceeding, namely that each utility's unique circumstances and the pace of technological change make it unnecessary, and likely counterproductive, to impose uniform, one-size-fits-all standards, such as the EISA 2007 Smart Grid Information and Investment Standards. The better approach is to use the Commission's existing authority to ensure the prudence of utility proposals and deployments concerning smart technologies, as the Commission currently does concerning all utility operations and investments.

- AG: The Attorney General does not oppose the economical use of smart technologies consistent with the other comments expressed by the Attorney General in this report. Consistent with the reasons stated in this chapter, the Attorney General concurs with the unanimous agreement of the Joint Utilities that the Commission should not adopt EISA 2007 Smart Grid Information and Investment Standards.

- CAC: No comments.

The Joint Utilities, AG, and CAC have appreciated the opportunity to meet to share views and learn from one another on these issues; however, including Case No. 2008-00408, the predecessor case to this case, the Commission and the Joint Utilities, AG, and CAC have been examining these issues, and particularly the EISA 2007 Smart Grid Standards, for five and a half years. The Joint Utilities have not changed their views during that time. Moreover, the Joint Utilities have made additional investments in smart and advanced technologies in the interim that have been subject to the Commission's existing rate and other review processes; none of the Joint Utilities believes these reviews have provided inadequate opportunities to review such investments for the parties desiring to seek such review. Therefore, the Joint Utilities' unanimous view is that the Commission should issue a final order closing this case without further proceedings and declining to impose the EISA 2007 Smart Grid Information Standard, the EISA 2007 Smart Grid Investment Standard, or any other smart-technology-related standard.

DEFINITIONS AND SCOPE

Definitions and Scope

Broadly, this report addresses issues concerning Kentucky utilities' deployment and use of advanced or smart technologies, primarily in the electric grid. The Joint Utilities define "advanced" or "smart" technologies in this report to comprise two categories of components:

- Meters and related system elements that communicate energy usage information to a utility and its customers in ways that allow customers to manage their energy usage and provide the utility with more dynamic information to use in managing the electric system; and
- Grid-management technologies such as communication networks and intelligent controls that enable utilities to operate more reliably and efficiently the electric system while providing more visibility and security for system operators.

More particularly, this report addresses issues concerning Kentucky utilities' deployment and use of advanced or smart technologies only with regard to the nine topics the Commission prescribed: customer privacy, opt-out provisions, customer education (including health-related education), dynamic pricing, AMR and AMI deployment (including prepaid meters and remote disconnections),[5] cyber-security, cost recovery for smart-technology deployments and obsolete equipment, how natural gas companies might participate in the electric smart grid, and whether the Commission should adopt the EISA 2007 Smart Grid Investment and Information Standards.[6] The scope of this report is strictly limited to those topics.

Each of the first eight topics of this report has implications for the potential adoption of one or both of the EISA 2007 Smart Grid Investment and Information Standards. Therefore, in addition to the ninth substantive section of this report that exclusively addresses these standards, each of the other eight sections provides a brief discussion of how the Joint Utilities' views on the topic inform their views on the EISA 2007 standards.

[5] The Joint Utilities have renamed this section "Distribution Smart-Grid Components."
[6] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 7-8 (July 17, 2013).

CUSTOMER PRIVACY

Customer Privacy

I. Executive Summary

Customer privacy is an important issue independent of smart-technology considerations. Kentucky's utilities already gather, maintain, and protect sensitive customer information, including account information, sometimes banking information, and energy-usage information. As discussed below, there are already federal and state legal protections in place concerning customer information in utilities' possession, and government and industry groups are working to develop even more robust voluntary standards for utilities to consider. Kentucky's utilities have already gone beyond the legal requirements in place today; each utility member of the Joint Utilities has a voluntary customer-privacy policy or practice in force to ensure that only appropriate use is made of customer information. Therefore, the Joint Utilities conclude that a new mandatory customer-privacy standard is not necessary at this time, including the customer data provisions of the EISA 2007 Smart-Grid Information Standard. Instead, the Joint Utilities propose a list of terms to define and substantive items for utilities to consider when reviewing customer-privacy policies and practices, which list the Commission may find useful when addressing smart-grid or other customer-privacy-related utility proposals.

II. Scope of the Customer-Privacy Section

This section addresses rights and responsibilities concerning Kentucky utilities' gathering and authorized use of customer information, including customers' and other parties' access to such information. This section does not directly address unauthorized access to customer information, which the Cyber-Security Section of this report addresses.

III. Existing Customer-Privacy Law

There are existing federal and Kentucky statutes that apply to utilities to protect the privacy of personally identifiable customer information, including, but not limited to, social security numbers, dates of birth, and financial account information. Kentucky's utilities supplement these regulations with voluntary customer-privacy policies or practices designed to further protect proprietary data, including customers' utility-specific account information. These existing legal requirements and oversight by responsible governmental entities, in conjunction with utilities' voluntary customer-privacy policies or practices, adequately ensure the protection of utility customers' privacy, negating any potential need for additional privacy statutes or regulations.

At the federal level, the Federal Trade Commission ("FTC"), under its authority to police and penalize unfair or deceptive trade practices (15 U.S.C. § 45) and the authority of the federal Fair Credit Reporting Act (15 U.S.C. § 1681), has issued and enforced a Red-Flags Rule (16 CFR § 681.1), which requires each utility to develop a written "red-flags program" to detect, prevent, and minimize the damage that could result from identity theft. Although there is no standard red-flags checklist utilities must use, utilities may use multiple means to protect their customers from identity theft or fraud, including checking alerts, notifications or warnings from a consumer reporting agency, carefully reviewing suspicious documents, verifying suspicious personally identifying information, investigating suspicious activity relating to a covered account, and taking into account notices from victims of identity theft, law enforcement authorities, or others suggesting that an account may have been opened fraudulently.

More broadly, federal and Kentucky consumer-protection statutes prohibit utilities and other businesses from engaging in unfair or deceptive trade practices.[7] The Federal Trade Commission has construed its statutory authority concerning such practices to include the ability to take enforcement actions against businesses that violate their own voluntary privacy policies.[8] The FTC has vigorously used its authority to protect customers: "As of May 1, 2011, the FTC has brought 32 legal actions against organizations that have violated consumers' privacy rights, or misled them by failing to maintain security for sensitive consumer information."[9] Therefore, utilities' voluntary privacy policies are not aspirational; rather, they are enforceable standards with which utilities must comply.

The Kentucky statute most directly applicable to utilities' use of customer information is KRS 278.2213(5), which limits a utility's ability to share confidential customer information with its affiliates: "No utility employee shall share any confidential customer information with the utility's affiliates unless the customer has consented in writing, or the information is publicly available or is simultaneously made publicly available." The Commission has the authority to penalize violations of this restriction under KRS 278.990, including the imposition of civil fines or criminal penalties.

Finally, customers harmed by their utilities' privacy-policy violations may have causes of action against the offending utilities.[10] This enforcement mechanism, along with all the others described above, give Kentucky utilities ample reasons to take all reasonable steps to protect their customers' privacy.

IV. Voluntary Standards for Customer Privacy

In addition to legal requirements concerning customer privacy, government entities and industry groups are working on voluntary customer-privacy standards that utilities may adopt. The Joint Utilities support these efforts, and will continue to monitor these and other developments, and may voluntarily adopt all or portions of such standards to the extent they are appropriate for their customers.

[7] *See* 15 U.S.C. § 45; KRS 367.170.
[8] *See* http://www.ftc.gov/opa/reporter/privacy/privacypromises.shtml
[9] *Id.*
[10] *See, e.g.*, KRS 446.070, which provides a private right of action to recover any damages incurred as a result of the violation of any Kentucky statute.

CUSTOMER PRIVACY

A. The U.S. Department of Energy ("DOE") and Federal Smart Grid Task Force Voluntary Code of Conduct

The U.S. Department of Energy and the Federal Smart Grid Task Force are facilitating a multi-stakeholder process to develop a Voluntary Code of Conduct ("VCC") for utilities and third parties providing consumer energy use services that will address privacy related to data enabled by smart-grid technologies. The Federal Smart Grid Task Force met twice in 2013 and has posted a draft set of possible VCC elements.[11]

B. The Energy Service Provider Interface ("ESPI") standard

The North American Energy Standards Board ("NAESB") and the National Institute of Standards and Technology ("NIST") have developed an ESPI standard. The ESPI standard contemplates a framework where the customer information collected by a utility is transferred to "data custodians" who would then, pursuant to certain rules and guidelines, authorize third parties to access the customer information. The purpose of the ESPI standard is to support the development of innovative products that will allow consumers to better understand their energy usage and to make more economical decisions about their usage. The NAESB ESPI standard provides model business practices, use cases, models, and an XML schema that describe the mechanisms by which the orchestrated exchange of energy usage information may be enabled.[12]

V. Current Customer-Privacy Protections of Utilities in Kentucky

In addition to complying with all applicable legal requirements and other industry standards concerning customer privacy, each of the Joint Utilities already has a voluntary customer-privacy policy or practice to protect its customers' information. These policies and practices vary, but all serve to ensure that Kentucky utilities appropriately use and share customer information.

VI. Joint Utilities' Customer-Privacy Proposal

Every utility should have a customer-privacy policy or practice, but the content of each policy or practice must address each utility's unique blend of services and customers. Although the precise terms of each utility's policy or practice will necessarily differ, each utility's policy or practice may define some or all of the terms and address some or all of the items below.

A. Possible privacy-related definitions

Defining some or all of the following terms may help to clarify a utility's customer-privacy policy or practice. This list is intended to be illustrative, not exhaustive or prescriptive:

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11 https://www.smartgrid.gov/news/doe_addresses_privacy_data_enabled_smart_grid_technologies_convenes_multistakeholder_process

12 http://www.naesb.org/ESPI_standards.asp

CUSTOMER PRIVACY

1. Utility. It may be helpful for a utility to clarify whether it intends "utility" to include the utility's contractors or other agents with whom it is necessary to share customer information.

2. Customer. A utility may want to define who is a customer or other authorized user for the purposes of its privacy policy or practice. Note that KAR 5:006, Section 1, defines "customer" as "a person, firm, corporation, or body politic applying for or receiving service from a utility."

3. Third party. This definition may relate to the definition of "utility" and "customer," and may include governmental entities or agents, non-profit utility-assistance organizations, or non-contractor businesses with which the utility interacts.

4. Privacy. This definition will likely state that privacy is the non-disclosure of customer information to third parties without the customer's consent. The remainder of the utility's privacy policy will flesh out when customers may reasonably expect the utility to assure privacy.

5. Customer information. A utility may delineate what information is operational data versus customer information, the latter of which might be subject to privacy protections.

6. Operational data. If a utility defines "customer information," it may define "operational data" to clarify which kinds of information are subject to privacy protections and which are not. Operational data may include, but not be limited to, general utility information and data about system operations.

7. Personally identifiable information. A utility's privacy policy or practice may seek to permit the utility to disclose certain information about customers to people or entities other than the customers themselves. If so, the utility may define a set of information it will not disclose, barring a legal obligation to do so, as "personally identifiable information." Personally identifiable information will presumably be a subset of customer information.

8. Anonymous. A utility may want to define how customer information may be disclosed to parties other than the customer while protecting the identity of that specific customer.

9. Aggregate. A utility may define when and how it may disclose customer information combined in one data set. The utility may also want to

address how it will ensure each customer's personally identifiable information is kept confidential when making such disclosures.

10. Consent. A utility may define what constitutes a customer's consent to disclose any or all customer information under a variety of circumstances. What constitutes adequate consent may differ depending on the scope of the disclosure and the kind of party to whom the utility will make the disclosure.

11. Utility use. A utility may define, likely in an illustrative, non-exhaustive way, when the utility may use a customer's information without first obtaining the customer's consent.

B. Checklist items

A utility may also address the following items in a customer-privacy policy or practice:

1. Scope; covered data. A privacy policy or practice may clearly state what kinds of information and which parties the policy or practice addresses, as well as what kinds of information and which parties it does not address.

2. Availability and access. A privacy policy or practice may address the terms and conditions on which the utility will make customer information available to the utility, customers, and third parties (possibly including government agents or entities, including law enforcement and regulatory agencies), as well as how such parties may access customer information. The terms of availability and access may differ depending on who is seeking the customer information, the precise kind of customer information at issue, and the purpose for accessing the customer information.

VII. Other Customer-Privacy Issues a Utility May Address

Utilities may address other issues concerning customer privacy, including, but not limited to, the issues listed below, either in their customer-privacy policies or practices or by other means.

A. Cost recovery for providing customer information

A utility's reasonable costs to make customer information available to requesting customers or in the context of a regulatory proceeding should be recoverable through the utility's rates. For example, a utility's reasonable costs to build and maintain a website that customers can use to access account and usage information should be recoverable through rates. But utilities should be permitted to establish reasonable charges to provide customer information to non-customers because such costs are not necessary for providing service and should be borne by the cost-causers.

CUSTOMER PRIVACY

B. Aggregation

Except as legally required, e.g., in the context of a regulatory or legal proceeding, utilities should not be required to provide aggregated customer information. Any obligation to provide aggregated customer information to non-customer and non-regulatory requesting parties could potentially divert utility resources from important utility functions, and may create an unnecessary privacy-violation risk.

C. Enforcement

A utility may address the means for enforcing its customer-privacy policy, perhaps by providing means of addressing perceived privacy concerns with customers in addition to those provided by law.

D. Liability

Utilities safeguard important customer information every day. As noted above, there are existing legal standards and obligations utilities must meet to protect the privacy of customer information. But utilities that desire to provide stronger protections for customers than those legally required create additional liability concerns for themselves; as discussed above, federal and state laws create potential liability for violations of purely private and voluntary customer-privacy policies. This liability may take the form of civil penalties levied by regulators or civil actions brought by aggrieved customers. This is a significant disincentive for utilities to implement more robust customer-privacy policies.

A possible means of reducing or removing this disincentive would be a new statutory framework that would limit or eliminate utilities' civil liability for merely negligent violations of their own voluntary customer-privacy policies. Such a framework would still serve to punish truly bad actors, such as those who violate customers' privacy intentionally or by gross negligence. But it would protect utilities whose intent and actions demonstrate their commitment to greater customer privacy protections than those currently prescribed by law.

E. Rights and responsibilities concerning customer information

A utility's privacy policy or practice may include a thorough delineation of the utility's and the customer's respective rights and responsibilities regarding customer information.

VIII. Customer-Privacy Aspects of the EISA 2007 Information Standard

Certain portions of the EISA 2007 Information Standard have customer-privacy implications. The Joint Utilities address them below:

"Customers shall be able to access their own information at any time through the Internet and by other means of communication elected by the electric utility for smart grid applications."

CUSTOMER PRIVACY

The Joint Utilities oppose making this provision mandatory. Kentucky's utilities do and will provide cost-effective means for customers to access their own data, which may include access via the Internet. But what is cost-effective for one utility may not be for another, and each utility's customers have different needs and desires concerning access to their information. Therefore, the best approach is for each utility to address its customers' needs economically, not subject to a one-size-fits-all mandate; however, if the Commission determines to implement such a requirement, it must allow utilities to recover the cost to build and maintain systems needed to provide the required information.

"Other interested persons shall be able to access information not specific to any customer through the Internet."

The Joint Utilities oppose this requirement as unnecessary, potentially costly, and risky. Meeting such a requirement will impose costs on utilities to implement and maintain systems to provide the necessary information and keep it current. Also, the terms "other interested persons" and "information not specific to any customer" are vague at best, and would need to be clarified before such a standard could be considered. Finally, utilities should provide aggregated data only on request and with appropriate safeguards; any other approach could create potential customer-privacy concerns.

"Customer-specific information shall be provided solely to that customer."

The Joint Utilities oppose this requirement because utilities must be able to provide certain customer-specific information to contractors in order to provide economical service to their customers. Also, utilities occasionally need to provide such information to legal or regulatory authorities, as well as to credit-reporting agencies to determine credit requirements. Certainly utilities should provide customer-specific information to people or entities other than the customer only if strict privacy safeguards are in place.

IX. Conclusion

The significant legally required and voluntarily implemented customer-privacy protections Kentucky's utilities have in place today negate any need for a new mandatory customer-privacy standard. Each utility's policy or practice will likely be different to meet the unique needs of the utility and its customers, but the list proposed above provides a useful framework of concepts for each utility and the Commission to consider when evaluating customer-privacy-related utility proposals. This voluntary-checklist approach will ensure utilities have the flexibility they need to continue to provide safe, reliable, and economical service while protecting their customers' privacy.

X. AG Comments

A state-wide mandated customer privacy standard containing the following items is absolutely essential:

CUSTOMER PRIVACY

1. Significant civil penalties for a utility that violates the standard either through common negligence, gross negligence or willful violation;[13] and

2. A single, clearly defined and universal "opt-in" method which would prevent a utility from disclosing non-aggregated, customer-identifiable information, unless the customer affirmatively elects to allow the utility to do so.[14] This would apply to any scope of disclosure.

Disclosure of customer information in the private sector, whether inadvertent or negligent, has occurred more with more frequency in recent years, at least as it has been published. Moreover, some of the information that has been compromised has led to significant detrimental consequences to both the customers as well as the companies involved.[15] Disclosures of utility customers' information could lead to similar results. Thus, the only way for utilities to ensure their customers' continued trust is to ensure that the utilities take every reasonable precaution, and that any deviations from such precautions would subject the utilities to significant penalties.

XI. CAC Comments

Non-profit agencies that assist utility customers with bill payment should not be charged for customer information requested in regulatory proceedings or in connection with providing the assistance. Aggregated customer information should be provided to a non-profit agency that assists utility customers with bill payment if such information is needed to facilitate that assistance.

[13] This may require amendment of KRS 278.2213 or KRS 278.990.
[14] NASUCA Resolution 2011-08, "Urging State and Federal Officials to Adopt Laws and Regulations Requiring Electric Utilities to Protect the Privacy Rights of Customers by Prohibiting Unauthorized Disclosure of Personal Information, Including Energy Usage Data," is an excellent model and could be adopted. For full text, see: http://nasuca.org/energy-privacy-resolution-2011-8/
[15] For example, *see* the 2013 Target Corporation breach, where approximately 110 million credit and debit card numbers were stolen and Target's fourth quarter profits experienced a 46 percent decline worth $520 million. http://www.nytimes.com/2014/02/27/business/target-reports-on-fourth-quarter-earnings.html?_r=0

OPT-OUT PROVISIONS

Opt-Out Provisions

I. Executive Summary

Customer concerns over purported health and privacy impacts of smart meters have caused some states to require utilities to offer opt-out provisions from smart-meter deployments. But requiring utilities to offer opt-outs from smart-meter deployments has potentially significant cost and operational impacts for utilities and customers, both those who choose to opt out and those who do not. Determining how to allocate the direct and indirect costs of opt-out provisions among customers who opt out and those who do not is also a challenging issue. This section provides an analytical framework for utilities and regulators to consider when evaluating the merits and consequences of various opt-out approaches.

II. Scope of the Opt-Out Section

This section addresses the cost and operational impacts of customer opt-outs from technological or informational components of large-scale utility deployments of smart meters. These include impacts to utilities and customers, as well as reductions in service levels and service-offering constraints to customers who choose to opt out, as well as cost increases associated with opt-out provisions.

This section does not address opt-outs from AMR metering. The Joint Utilities believe no opt-outs should be permitted from AMR deployments, and a number of utilities have already deployed AMR system-wide. Therefore, this section addresses only smart-meter (AMI) deployments.

III. Customer Concerns Related to Opt-Outs

Generally, a smart-technology deployment creates the greatest benefits relative to its costs if it is ubiquitous. To the extent a smart-technology deployment involves smart meters, allowing individual customers to opt out, particularly to opt out of the technology deployment, eliminates ubiquity, reducing the benefits of the overall deployment and creating additional costs for the utility and its customers. Therefore, utilities tend not to have cost or operational reasons to support opt-outs.

Some individual customers, however, have raised concerns in smart-meter deployments to argue in favor of opt-outs (or simply to oppose a smart-meter deployment at all). The two primary objections such customers raise are that smart meters will adversely affect their health and that smart meters invade their privacy. With respect to health, some members of the public believe that the electromagnetic radiation smart meters emit can cause adverse health effects, notwithstanding significant scientific evidence to the contrary.[16] Customers' privacy concerns arise from the belief that smart meters can record and report to utilities and other government agencies customers' electricity usage on an interval basis, notwithstanding utilities' assurances that smart meters are not "surveillance devices," and that utilities guard customer information

[16] http://www.whatissmartgrid.org/smart-grid-101/fact-sheets/radio-frequency-and-smart-meters

gathered from smart meters with the same privacy protections used to protect all customer information.[17]

A smaller subset of customers have the mistaken impression that any digital meter is a smart meter capable of at least one-way communications, and want to opt-out of any digital-meter installation. The Joint Utilities oppose opt-outs of any kind for digital meters with no communications capabilities for two reasons: (1) such meters are essentially identical to older electromechanical meters; and (2) the Joint Utilities do not believe electromechanical meters are being manufactured domestically today, making any opt-out from a non-communicating digital meter impracticable at best.

IV. How Utilities and Other States Have Addressed Opt-Outs

Several of the Joint Utilities have deployed smart-meter technology and have addressed the customer concerns described above, as well as opt-outs and opt-out requirements in other states.

The unanimous view of the Joint Utilities that have made significant smart-meter deployments is that customer education and high-touch customer service are crucial to overcoming customer objections, regardless of the availability of opt-outs. For example, Duke Energy's Ohio smart-meter rollout involved sending postcards to customers before swapping out their existing meters with smart meters, calling the same customers one to two weeks prior to swap-out, and following up with letters. For customers who voiced concerns and did not want a smart meter installed, Duke's customer-service team would contact the customers, including one-on-one visits, to address their concerns. Duke indicated that this high-touch customer service and communication approach satisfied the concerns of nearly all of their Ohio customers, and the same approach seems to be having similar success in the Carolinas, where Duke is now deploying smart meters.

American Electric Power ("AEP") has used similar processes to respond to customers expressing concerns with smart-meter installations in Texas, Ohio, Oklahoma, and Indiana. When provided with answers responsive to their questions, the vast majority of customer concerns are alleviated, and they no longer object to smart-meter installations. AEP's experience is that the percentage of customers that continue to object to smart-meter installations after having their concerns addressed is less than 0.01%.

The distribution cooperative members of the Joint Utilities have had similar experiences with their AMR and smart-meter deployments in Kentucky. By providing pre-deployment information to customers and having direct contact with customers expressing concerns, the cooperatives have been able to address most of their customers' objections or concerns. There have been a few instances where this approach has been unsuccessful, but they have been rare.

[17] http://www.whatissmartgrid.org/smart-grid-101/fact-sheets/data-privacy-and-smart-meters

OPT-OUT PROVISIONS

There are opt-out requirements in some other states where AEP has operations. For example, AEP Texas recently received approval from the Public Utility Commission of Texas for its compliance filing to establish opt-out rates. AEP Texas will now charge opting-out customers an up-front opt-out charge in addition to an ongoing monthly opt-out charge. Duke Energy stated there are currently no opt-out requirements in North Carolina, South Carolina, Florida, Indiana, and Kentucky, and that Duke has not offered opt-outs in any of those jurisdictions.

The Public Utilities Commission of Ohio approved a residential customer "advanced meter" opt-out rule on December 18, 2013, during its regularly scheduled rule-review process that occurs every five years.[18] The updated rules became effective May 29, 2014. The new opt-out rule defines an advanced meter as "any electric meter that meets the pertinent engineering standards using digital technology and is capable of providing two-way communications with the electric utility to provide usage and/or other technical data." The rule requires also that costs incurred by an electric utility to provide advanced meter opt-out service shall be borne only by customers who elect to receive an advanced meter opt-out service. The electric utilities are to file on or before June 28, 2014, an advanced meter opt-out tariff that will include a one-time fee and a recurring fee for the optional residential opt-out service.

More broadly, most states do not have smart-meter opt-out policies. The states that do have such policies range from Vermont, where state statute requires utilities to offer opt-outs at no cost to their customers,[19] to Texas, where the commission has issued an administrative regulation requiring transmission and distribution utilities to offer opt-outs and have tariffs stating the initial and ongoing charges opting-out customers must pay.[20] Although the costs associated with opt-outs will vary by utility, an example of the initial and ongoing charges for opting-out customers the Joint Utilities' research uncovered was in Oregon, where Portland Gas and Electric charges opting-out residential customers an initial opt-out fee of $254 and a monthly opt-out charge of $51.[21] Because each utility and the Commission will need to calculate costs on a utility-by-utility basis, those fees may not be indicative of the opt-out fees appropriate for Kentucky's utilities.

The Joint Utilities' research indicates that the size of the opting-out population is relatively small for most utilities that offer opt-outs. An article by Chris King of eMeter looked at opt-out programs in a handful of states: Maine, California, Texas, Michigan and Nevada. In his research, Maine had the highest percentage of customers choosing to opt out (1.4%),[22] and

[18] *In the Matter of the Commission's Review of Chapter 4901:1-10, Ohio Administrative Code, Regarding Electric Companies*, Public Utilities Commission of Ohio Case No. 12-2050-EL-ORD, Finding and Order (Dec. 18, 2013).
[19] *See* http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=077&Section=02811 (information on Vermont Senate Bill 214).
[20] *See* http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.133/25.133.pdf.
[21] *See* Non-Network Residential Meter Rates at:
http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_300.pdf
[22] *See* http://www.elp.com/articles/powergrid_international/print/volume-17/issue-11/features/smart-meter-opt-out-policies-explain.html.

the average percentage of opting-out customers of the utilities studied was 0.4%.[23] But even one opting-out customer can create significant costs, as discussed below.

V. Opt-Out Considerations

The Joint Utilities present below an analytical framework for considering opt-outs that may help a utility or regulator understand the effects of pursuing a particular opt-out approach.

A. Opt-Out Costs

Although utilities would bear certain opt-out costs in the short term, customers would bear the increased costs in the long term. The list below, though not exhaustive, contains a number of important costs for utilities and regulators to consider, regardless of whether the costs are socialized or charged to the cost-causers:

1. Increased meter-reading costs. One of the chief cost savings smart meters provide is automated meter reading, eliminating much of a utility's cost for labor, vehicle dispatch and operation (including cost and liability associated with possible vehicle collisions), and data systems associated with manual meter-reading.

2. Increased meter-inventory costs. Carrying an inventory of smart and traditional meters, meter parts, and meter-service equipment, both on utilities' service trucks and in their warehouses, increases inventory costs relative to carrying only one variety of such equipment.

3. Increased staffing costs. In addition to labor costs associated with manual meter-reading in the field, opt-outs would create other additional labor and staffing costs relative to a no-opt-out approach, including back office and customer service costs associated with addressing customer questions, service issues, and data entry and management, all of which would differ between smart-meters and traditional meters.

4. Increased system-planning costs. Smart meters give utilities insights into the performance of their distribution systems that traditional meters cannot provide, including load and voltage data that enable utilities to improve and make more efficient their system planning and operation. A sufficiently low saturation of smart meters in a given area could compromise that improvement, adding a relative cost to a utility's system planning.

5. Increased system-restoration costs. Smart meters help utilities find and repair outages more quickly and with greater precision, which helps

[23] *Id.*

reduce system-restoration costs and outage durations. Opt-outs would compromise this advantage.

6. Costs for changing meters for opt-outs (pulling smart meters). Customers who move into premises already equipped with smart meters and choose to opt out will create costs to replace their existing smart meters with traditional meters. The cost such customers create could actually be double the initial meter swap cost; when new, non-opting-out customers subsequently occupy the premises vacated by opting-out customers, more meter swaps will be necessary.

7. Reduced line-loss-reduction opportunity. Smart meters help detect line losses. When used with other smart technology, this information can be used to more efficiently plan and operate distribution circuits. Reduced concentrations of such meters due to opt-outs reduce that capability.

8. Decreased theft detection; decreased hazard reduction. Smart meters can help minimize theft of service and reduce potential hazards from meters that are supposed to be idle by reporting electric usage. Also, smart meters have thermocouples that can detect certain unsafe operating conditions, such as hot sockets, undetectable by traditional meters.

9. Reduced opportunity to find missing meters. Smart meters' communications capabilities can help utilities find missing meters; traditional meters lack such capabilities.

10. Reduced opportunity to identify malfunctioning meters early. A utility may not detect a malfunctioning standard meter for some time, resulting in the need to estimate billing for the malfunction period. Smart meters help identify their own malfunctioning early, which minimizes the amount of estimated billing. A customer that opts-out would lose this benefit. With an AMI meter, the utility has the ability to monitor the non-communicating meters and investigate and mitigate to minimize estimated billing. Also, AMI systems support the identification of failed metering equipment, enabling utilities to repair or replace such meters more quickly. This reduces the amount of time a utility would have to use estimated billing

11. Additional service costs. Smart meters enable a utility's customer service team to "ping" a customer's meter to determine if it is functioning properly, which could avoid a customer's having to pay for an unnecessary service call. AMR meters have only one-way communications, and therefore do not permit "pinging."

OPT-OUT PROVISIONS

B. Operational Impacts of Opt-Outs

In addition to cost impacts, opt-outs have operational impacts that affect utilities and customers who do not opt out. For example, to the degree opt-outs reduce a utility's ability to monitor the condition of the grid, opting-out customers can negatively impact the utility's ability to serve all other customers, as well. Therefore, utilities and regulators may want to consider the following non-exhaustive list of operational impacts caused by opt-outs:

1. Staffing. Maintaining, servicing, and providing customer service for what would essentially be two distribution systems—one automated, one traditional—will place additional demands on utility personnel.

2. Technology. In addition to the cost impact, there is an operational impact of maintaining two sets of meters, meter parts, and meter-servicing equipment.

3. System planning. Opt-outs will require additional engineering analysis relative to system planning with ubiquitous smart meters.

4. System restoration and individual restoration. As discussed in the utility costs section above, smart meters can help reduce system, circuit, and individual restoration times. The absence of such meters relatively increases the difficulty and time associated with restoration.

5. Reliability and power quality. Smart meters can help maintain distribution system reliability and power quality, e.g., by interrogating particular meters concerning voltage issues.

6. Remote connections and disconnections. Utilities can perform service connections and disconnections nearly instantaneously with smart meters equipped to do so, and without the need to dispatch service personnel.

7. Off-cycle meter readings. In addition to normal meter readings, smart meters reduce the need for utility personnel to travel to customer premises to perform off-cycle meter readings, e.g., when a customer ends service at a particular premise. Opt-outs reduce this operational benefit.

8. Safety impacts. Fewer dispatches of utility personnel resulting from smart-meter deployments should reduce vehicular accidents, slips and falls, and other potential safety issues. Opt-outs will reduce this operational benefit.

9. Customer safety. As discussed in the utility costs section, smart meters can inform utilities about hazardous operating conditions that may impact customers' safety, including hot sockets and bad connections.

OPT-OUT PROVISIONS

10. Availability of products and services. Smart meters enable utilities to offer customers enhanced products and services relative to what a utility can offer with traditional meters; customers without smart meters would therefore be unable to use such products and services. These could include:

    a. Dynamic pricing

    b. Enhanced energy efficiency

    c. Increased ability for customers to understand energy usage

    d. Prepaid service

11. Physical privacy, security, and convenience. Particularly for customers who currently have indoor analog meters, smart meters will increase privacy, security, and convenience by reducing a utility's need or means to access its customers' premises. Therefore, customers opting out of such meters might actually reduce their relative privacy, security, and convenience.

12. Ongoing system reconfiguration. Opting-out, as typically considered, is not a static condition, which can have significant cost impacts on serving customers. For instance, if the smart-meter communications network is arranged optimally for universal coverage and a customer subsequently opts out, the ability of a utility to monitor the condition of that circuit and reach other customer meters for communications can easily be disrupted, essentially creating a blind spot in the network. This situation could require expensive reconfiguration of the network to accommodate. If other customers elect to opt out and opt in again over time, the constant reconfiguration of the system could quickly overwhelm the operational and cost benefits of the technology upgrade itself.

13. Meter testing. Because the number of opting-out customers is likely to be small, existing meter-testing requirements (807 KAR 5:041 §16) will require most, if not all, opting-out customers' meters to be tested annually to ensure a statistically valid sample in accordance with the sampling technique the serving utility uses for all other meter groups.

14. Regional Transmission Organization ("RTO") impact. For utilities that are members of RTOs, a customer opt-out feature may impact the ability of those utilities to optimize RTO power purchases or sales.

OPT-OUT PROVISIONS

C. Defining "Opt-Out"

A threshold issue to consider when addressing opt-outs is what an opt-out entails. As typically considered, an opt-out requirement for smart metering is opting out of the technology entirely, i.e., a customer's refusal to have a smart meter installed on the customer's premises. Technology opt-outs are what the state standards and approaches above have assumed and required.

Another kind of opt-out that may be technically feasible in some, but certainly not all, smart-meter deployments is an informational opt-out. An informational opt-out would permit a utility to install a smart meter, but would allow each customer to decide the kinds of information the utility could collect remotely. For example, a customer could find daily meter readings to be a privacy problem and ask the utility to read the meter only once per billing period. This kind of informational opt-out would permit a smart meter to perform some useful functions, e.g., report outages, while potentially satisfying a customer's particular privacy concerns.

But informational opt-outs, even where technically feasible, might still fail to address customers' concerns. For example, such an opt-out would not address customers' health concerns about communicating meters. Also, some customers might not believe that utilities are collecting only the information they say they are collecting. These issues cast serious doubt on the usefulness of informational opt-outs' ability to allay customer concerns.

In addition to being potentially unsatisfying to customers who have concerns about smart meters, informational opt-outs have considerable costs. Some are utility-wide, such as the costs of designing and building a system capable of handling such opt-outs and training customer-service personnel to use it to address customer requests. Some costs would impact customers choosing to opt out, such as losing the ability to monitor daily usage patterns that could be useful to the customer's energy-conservation efforts. And depending on the information customers could choose to refuse to provide, informational opt-outs, like technology opt-outs, could impair the overall effectiveness of a utility's smart-meter deployment.

Regarding the costs described in Section V.A. "Opt-Out Costs" above, the following costs would not apply to informational opt-outs, though all the remaining costs listed in that section would apply:

- Increased meter-reading costs
- Increased meter-inventory costs
- Increased system-restoration costs
- Costs for changing meters for opt-outs (pulling smart meters)
- Reduced line-loss-reduction opportunity

- Decreased theft detection; decreased hazard reduction
- Reduced opportunity to find missing meters
- Additional service costs

Regarding the operational impacts described in Section V.B. "Operational Impacts of Opt-Outs" above, the following impacts would not apply to informational opt-outs, though all the remaining impacts listed in that section would apply:

- Technology
- System restoration and individual restoration
- Reliability and power quality
- Remote connections and disconnections
- Off-cycle meter readings
- Safety impacts
- Customer safety
- Physical privacy, security, and convenience
- Ongoing system reconfiguration
- Meter testing

With regard to technical feasibility, informational opt-outs might be workable for some smart-meter deployments but not others, principally based on the underlying technology for back-haul communications. For power-line-carrier-based deployments, informational opt-outs might be feasible if the appropriate smart components were in place. For radio-frequency-based deployments, informational opt-outs would pose such significant operational challenges as to be infeasible, i.e., informational opt-outs are impracticable with radio-frequency based deployments.

D. Customer education

Regardless of whether a utility offers opt-outs or what kind of opt-outs it offers, it should consider engaging in a pre-deployment customer-education campaign to address potential customer concerns about smart meters. Pre-deployment campaigns may include information about when and how meter changes will occur, the benefits of smart meters to individual customers and the utility as a whole, and new or enhanced services that will follow smart-meter installation. Utilities should provide accurate and reliable information to address any health and

OPT-OUT PROVISIONS

privacy concerns some customers may have about smart meters. The utility may also want to consider focused efforts to assist objecting customers by contacting them individually to hear their concerns and provide objective data to correct any misinformation they might have received, as well as to provide information on the cost of opting out and the services and benefits the customer would forgo by opting out.

E. Other issues

In addition to the cost and operational issues above, utilities and regulators may want to consider the following issues concerning opt-outs:

1. Meter availability. To the best of the Joint Utilities' knowledge, analog meters are no longer being manufactured domestically.

2. Systems with existing smart-meter deployments. Several of the Joint Utilities have already deployed smart meters, some across their entire service territories. Introducing opt-outs in those territories would create real and new, not relative and potential, costs.

3. Assigning opt-out costs. As discussed above in the section concerning how other states and utilities are addressing opt-outs, there is no consensus concerning whether opt-outs should be permitted at all, and to the extent they are permitted, whether those opting out should bear the full cost of their decision (and how to calculate that cost), or whether opt-out costs should be fully socialized across each customer class. Basic cost-causation principles, including preventing subsidies between customers of the same rate class, support requiring customers who opt out to bear the full cost of their choice; however, if opt-outs are permitted, making each customer bear the full opt-out cost may prohibit some customers from opting out. Each utility and the Commission must address these issues if the utility offers opt-outs.

4. Opt-out exceptions. Utilities must have the right to refuse to honor opt-out requests in certain situations, such as where safety, access, or meter tampering must be addressed. In particular, customers who have indoor meters should not be permitted to opt out unless they move their meters outside at their expense. Utilities deploy smart meters in these situations today, and opt-outs should not constrain utilities' ability to do so.

5. Rate design and cost-of-service-study impacts. In addition to assisting with system planning, smart-meter data can improve the precision of rate design and cost-of-service studies. For example, demand and usage data may help utilities better understand which customers and customer classes are imposing demands on utility systems and which are not, which may help utilities to craft rates that more accurately recover costs from cost-

causers. Permitting too many opt-outs of any kind may reduce this benefit.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Opt-Outs

Opt-outs, particularly technology opt-outs, are contrary to the overall thrust of the EISA 2007 Smart-Grid Investment and Information Standards. Opt-outs will inhibit a customer's ability to obtain timely information about usage and participate in dynamic pricing, and a critical mass of opt-outs may cause a planned smart-technology deployment to cease to be economical. Because the EISA 2007 Smart-Grid Standards were intended to encourage states and utilities to implement smart-grid technology, allowing customers to opt out would undermine the objectives of the EISA 2007 Smart-Grid Investment and Information Standards.

VII. Conclusion

All of the Joint Utilities agree that the analytical framework above is a fair representation of the costs, impacts, and other challenging issues opt-outs present.

Further, all of the Joint Utilities agree that the cost impacts and reduced operational capabilities (to both opting-out customers and all other customers) of requiring opt-out arrangements are not generally beneficial on the whole. As each utility's customers and potential (or actual) smart-meter deployment arrangements are unique, a case-by-case approach using some or all of the analytical framework presented above may therefore be an appropriate approach to evaluate opt-outs. Therefore, the Joint Utilities oppose any across-the-board, one-size-fits-all opt-out requirement for smart-meter deployments, but support each utility's ability to propose opt-outs appropriate for their customers and systems.

VIII. AG Comments

The Attorney General agrees with the utility stakeholders that ratepayers' two main concerns related to deployment of smart-meters are health and privacy. He also agrees that various types of opt-outs are available, and should be available to ratepayers. The types of opt-outs envisioned are informational opt-out and equipment or smart-meter opt-out.

Despite the utility stakeholders' assertions, very few independent scientific results have been produced demonstrating that smart meters are either safe or dangerous to human health. Subsets of ratepayers believe very strongly that smart meters are dangerous and harmful to human health. The research that Utility Stakeholders claim establishes the safety of smart meters has apparently been conducted primarily by interested parties. The Attorney General asserts that the lack of independent research on this topic suggests that rational minds can disagree on this point. As such, the beliefs of any customers concerned with the health impacts of smart meters should be viewed as bearing enough validity as to warrant use of an alternative to a smart meter.

As to the use of digital meters with no communication abilities, several complicating factors are at play. First, the utility stakeholders state that electromechanical meters are no longer manufactured domestically. The Attorney General acknowledges that the utility representatives are in a better position to secure this knowledge. However, to the best of the Attorney General's knowledge, utility stakeholders have to date made no effort to corroborate this belief. Second, preventing ratepayers from opting-out of digital meters puts a great deal of responsibility on the KPSC to ensure that a communicating meter has not been installed where a digital meter should have been. As utility stakeholders acknowledge, there are few if any visual characteristics to distinguish a digital meter from a meter capable of communicating. Thus, if ratepayers are not allowed to opt-out of a digital meter, this would place the onus on the KPSC to determine whether the meter is communication-capable, as well as to reassure customers that the meter servicing their dwelling is the proper model and has the proper capabilities.

The Attorney General strongly believes that opt-outs should be permitted. Further, if opt-outs are allowed, the KPSC must prevent utilities from taking any retaliatory actions against ratepayers electing to opt-out.

Whether an informational opt-out can be made available will likely depend, in large part, upon the type of system the utility installs. Some systems only receive smart-meter information after a central, main system requests information from the smart meter. Other systems are designed to transmit information at specific time intervals. Informational opt-outs would be relatively easy to offer for systems of the former type. Conversely, automatic, time-interval systems present additional technical challenges to informational opt-out. The Attorney General does not purport to be a technical expert on smart meters or communications. As such, the KPSC and its staff are in the best position to judge the availability and feasibility of informational opt-outs.

Finally, the Attorney General wishes to highlight the importance of customer education and consumer outreach when implementing a smart meter system. Companies that educate their customers and develop trusting relationships with customers experience significantly fewer opt-outs than utilities which do not engage their customers in this manner.

IX. CAC Comments

Customers should not be penalized for opting out. Further, although the Joint Utilities in this section have addressed the advantages of smart meter deployment, and costs, operational, and convenience impacts of opt-outs, they have not included the human impacts associated with opt-out issues. The ability to instantaneously remotely disconnect a customer for non-payment, though clearly an advantage to the utilities, can have devastating consequences for the low-income customers who struggle to keep heat on in the winter and air conditioning on in the summer, particularly the low-income elderly and those who suffer from certain illnesses. Simultaneous disconnection can prevent these low-income customers from having the ability to seek last-minute resources to avoid the shut-off. It is CAC's experience that last-minute avoidance is common, especially during the winter months. This consequence should be mitigated as smart meters are deployed.

CUSTOMER EDUCATION

Customer Education

I. Executive Summary

Customer education about the benefits of smart technology is critical to gaining customer acceptance and use of this technology. Several of the Joint Utilities have successfully used customer-education efforts, including pre- and post-deployment measures, to permit customers to increase the benefits of smart-meter deployments and address customers' concerns. Based on those utilities' successes, all of the Joint Utilities agree that each utility deploying smart meters should consider using some combination of the customer-education measures discussed in this section.

II. Scope of the Customer-Education Section

This section addresses customer education for utility deployments of smart meters. It includes summaries of certain utilities' experiences with customer education for smart-meter deployments, as well as lists of possible education topics, communication channels, and parties to engage in customer-education efforts concerning smart-meter deployments.

III. How Utilities Have Addressed Customer Education in Smart-Meter Deployments

Several of the Joint Utilities have deployed smart-meters and engaged in customer-education efforts associated with those deployments.

A. Duke Energy

Duke Energy has already designed a publicly accessible grid modernization webpage, with high-level information about grid modernization, frequently asked questions, and videos or external educational resources. Customers can find that webpage on their own if they have some interest in the topic or navigate through the site. As Duke Energy rolls out smart meters, customer-notice materials provide additional information related to installation at a customer's location as well as linking back to the Duke Energy grid modernization webpage for background information.

Duke Energy's proactive approach to communications with customers around smart meter deployment has involved:

- Sending postcards ahead of installation or having account managers reach out to large business customers;
- Canvassing neighborhoods to arrange for installation appointments if customer interaction is necessary to exchange meters, and leaving door hangers for customers that are not then available, so the customers can call to schedule an appointment;

CUSTOMER EDUCATION

- Making outbound calls to schedule installation appointments (when necessary) if prior attempts to schedule an appointment were unsuccessful;

- Sending letters for customers that still are unreachable to set meter exchange appointments;

- Sending a certification letter around 30-60 days after a smart meter was successfully installed and certified; and

- Sending a post-certification postcard two weeks after certification to direct customers to their Duke Energy web portal (different from general grid modernization webpage), so they can monitor their energy usage online.

B. American Electric Power

AEP has taken a simple, proactive, and transparent approach to educating customers about smart meters. Information about AMI meters and grid modernization, including frequently asked questions and videos, are available on the utility websites where these technologies are being deployed (AEP Ohio, AEP Texas, Indiana Michigan Power, and Public Service Company of Oklahoma). In addition to web resources, AEP utilities have:

- Communicated with customers multiple times via U.S. mail to announce the project and educate customers on the benefits of the meters prior to installation.

- Contacted each customer by phone prior to installing a new meter and left a detailed door hanger with the customer after installation was completed.

- Promoted through direct mail consumer programs and reinforced the benefits of the meters six months after installation.

- Dedicated customer service representatives to answer customers' questions and concerns.

- Spoken at many community and government meetings and with media outlets about the benefit of the meters, technology, and consumer programs available.

- Developed mobile exhibits to educate customers and local leaders on the benefits of the programs. The exhibits have been part of numerous community events and meetings.

C. Owen Electric Cooperative

Member education was a key element of Owen Electric's smart-meter deployment from 2006 to 2009. Owen used a host of communication channels to engage and educate its membership, including the Cooperative's member newsletter, billing inserts, door hangers, website, and direct conversations with individual members. Additionally, Owen used informational presentations to area officials, chambers of commerce, and civic and community groups to engage the community in the discussion.

For ongoing member education, Owen maintains a webpage and other materials devoted to smart meters and AMI technologies. Having well-trained customer service representatives and supervisors equipped to address member concerns and questions related to smart meters remains a priority. Owen believes it is crucial to offer personal (high-touch) attention to customers with smart meter/grid concerns.

IV. Customer-Education Topics

Based on the experiences of the utilities described above, the Joint Utilities present a non-exhaustive list of topics a utility may want to address in a customer-education effort for a smart-meter deployment. Utilities may want to address some or all of these topics or other topics at different times and in different ways with some or all customers depending on the stage of the regulatory or deployment process for a particular smart-meter proposal or deployment. For example, a utility may want to address certain topics as part of a broad-based pre-deployment communications plan, and others it may want to address in follow-up communications with customers who have questions or concerns.

A. System description

Customers may want to understand what the utility is deploying. This could include describing the smart meter itself, including its capabilities and features (e.g., automated meter-reading, two-way communications, power quality reporting, and fault detection), as well as how the smart meter fits in the utility's overall smart-technology deployment.

B. What to expect

A utility may want to inform its customers what they can expect from a smart-meter deployment. For example, customers accustomed to having meters read visually may want to know that their meters are indeed being read even though the customers are not receiving visits from a meter-reader. Also, a utility may want to provide customers with a schedule or timeline for when to expect activities to take place.

C. Benefits

Describing smart meters' benefits may help improve customer acceptance of the technology, as well as increase the realized benefits of a deployment by empowering customers to engage with smart technology's features. Some benefits a utility may want to include in its customer-education efforts are:

1. Better billing dispute resolution. Detecting meter errors or abnormal usage patterns early may help minimize the impact of billing disputes and lead to more rapid resolution of disputes that arise.

CUSTOMER EDUCATION

2. Helping customers understand their energy use. Smart meters can provide customers a more granular view of their energy usage patterns than traditional meters can provide. This additional information can empower customers to reduce or otherwise improve their energy usage. A utility may want to inform customers about how to access this additional information, such as through an online information portal.

3. Earlier notification of outages. The serving utility may want to inform customers that smart meters may lead to earlier notification of outages due to enhanced outage reporting capabilities and precise outage-location information.

4. Rate options. If a utility is offering new rate options associated with a smart-meter deployment, such as prepaid service or dynamic pricing (including time-of-use or time-of-day rates), it may want to communicate the new rate options to customers during its customer-education effort.

5. Improved meter-reading accuracy. Smart meters can result in fewer meter-reading mistakes by removing potential human error from the reading and recording process, and may result in fewer estimated meter reads.

6. Reduces need to go on customers' premises. Customers may anticipate relatively increased safety, as well as enhanced privacy, resulting from a reduced need for utility personnel to enter customers' premises due to smart meters.

D. Radio-frequency emissions

Some customers have received misinformation about the health effects of smart meters. Therefore, the utility deploying smart meters may want to provide accurate information about the small amounts of smart-meter radio-frequency ("RF") emissions. In particular, a utility may want to provide information about compliance with Federal Communications Commission ("FCC") standards, or provide studies from independent third parties such as the U.S. Department of Energy showing the safety of smart meters. It may also be instructive to compare the RF emitted by smart meters to RF emitted by items customers commonly use, such as microwaves, televisions, and cell phones.

E. Opt-out availability and costs

If a utility offers opt-outs from a smart-meter deployment, it should inform customers of customer-specific costs of opting out. A utility may want to include opt-out-cost information even if the costs are socialized to help customers understand the impacts of their decisions on other customers.

CUSTOMER EDUCATION

F. Privacy

A utility deploying smart meters may want to inform its customers of the information the utility will collect from the smart meters and how it will protect and use that information. Perhaps equally useful would be to inform customers what kinds of information the utility will not collect, e.g., information about which appliances a customer is using from moment to moment.

V. Communications Channels for Customer Education

Based on the experiences of the utilities described above, the Joint Utilities present below a non-exhaustive list of communication channels that may be available to a utility in its customer-education effort for a smart-meter deployment:

A. Door hangers

Door hangers can be useful pre-deployment to inform customers about local installation scheduling, as well as to provide other brief customer education.

B. Bill inserts and newsletters

Bill inserts and newsletters can provide more in-depth information concerning a smart-meter deployment. They can be used to educate customers pre-deployment, but can also be used to remind customers about smart-meter benefits, ways to use smart-meter-provided data, and post-deployment rate options.

C. Phone calls, text messages, and e-mail

Phone calls, text messages, and e-mail made by automated means can provide customers pre-deployment scheduling and contact information. Personal phone calls and e-mail can also help provide more in-depth education, and can address concerns for customers with objections to smart-meter installations.

D. Face-to-face meetings

Face-to-face meetings may assist in addressing the concerns of customers who object to smart-meter deployments.

E. Customer service representatives

Customer service representatives can be a crucial to any customer-education effort. They can address customers' concerns and provide valuable information about how customers can use smart-meter information to improve their energy usage. They can also inform customers about rate options available with smart meters.

F. Social media

Social media, including Facebook and Twitter, can be used to provide scheduling information and high-level customer education, as well as an interactive public question-and-answer platform.

G. Websites

Websites can provide full-spectrum customer education about smart-meter deployments. This can include in-depth customer education about all aspects of a deployment. Also, a utility's website would likely be the portal a customer would use to access account information, including any enhanced information a smart meter would provide.

H. Mass media advertising and public service announcements

Mass media advertising and public service announcements ("PSAs"), including newspaper, radio, and television advertising, can provide broad and brief customer education about overall deployment information, including contact information for customers with questions or concerns and website information for customers seeking more in-depth information. In addition to utility advertising, the Commission could provide PSAs about smart-meter deployments.

I. Partner organizations

Partner organizations such as local government (e.g., mayor, county judge-executive, county clerks, city councils, and city managers), civic organizations, and community action agencies, could help disseminate useful information about a deployment, and can address some questions and concerns.

J. Community forums

Community forums could be efficient means of addressing multiple customers' individual questions and concerns. With appropriate permissions and disclosures, videos of such forums could be useful tools to post on utilities' websites to address questions customers might have.

VI. Parties that Can Assist with Customer-Education Efforts

Several non-utility entities could assist in providing customer education concerning smart-meter deployments if utilities engage and educate them pre-deployment. These entities include, but are not limited to:

CUSTOMER EDUCATION

A. Local government

Mayors, county judge-executives, county clerks, city councils, and city managers could all be helpful resources in providing customer education because customers often approach local government with questions or concerns about utility activities.

B. Civic groups

Homeowners' associations, community action agencies, and other civic organizations have memberships and client bases that already turn to them for help in utility matters. Therefore, these organizations could be useful partners in customer education concerning smart-meter deployments.

C. Trade organizations

The Kentucky Industrial Utility Customers, Inc., the Kentucky Association of Manufacturers, the Kentucky Retail Federation, and other trade organizations could be valuable partners in distributing industry-specific information to customers during smart-meter deployments

D. Kentucky Public Service Commission

The Commission could be a valuable partner in customer education by providing reliable and independent information to customers inquiring about smart-meter deployments.

VII. EISA 2007 Smart-Grid Investment and Information Standards and Customer Education

Customer education supports the EISA 2007 Smart-Grid Investment and Information Standards. Customer education tends to increase the realized benefits of smart-meter investments, consistent with the Smart-Grid Investment Standard's consideration of cost-effectiveness. Likewise, customer education supports the tenets of the Smart-Grid Information Standard by directing customers to the enhanced usage information smart meters provide, as well as possible dynamic pricing options utilities may provide after a smart-meter deployment.

But as described above, utilities are already engaging in customer education concerning smart-technology deployments absent any imposition of the EISA 2007 standards. Indeed, the EISA 2007 standards do not directly address or require customer education; though customer education may support the goals of the EISA 2007 standards, the standards do not support customer education. Therefore, customer education and its benefits do not provide any reason to implement either of the EISA 2007 standards, and the Joint Utilities continue to oppose them.

VIII. Conclusion

Customer education, including some of the items discussed above, is likely to increase the success of any smart-meter deployment. By ensuring customers understand the benefits and features of the smart technology being deployed, a deploying utility can help minimize customer concerns and objections while increasing the likelihood that projected benefits will be realized as customers engage with the technology and use it to improve their energy consumption. Therefore, the Joint Utilities recommend that each utility deploying smart meters consider using some of the customer-education measures addressed in this section.

IX. AG Comments

The Attorney General has no additional comments with regard to this chapter.

X. CAC Comments

Customer education should be mandatory when smart meters are deployed.

DYNAMIC PRICING

Dynamic Pricing

I. Executive Summary

Several of the Joint Utilities have provided voluntary dynamic-pricing options to residential customers, both on trial and permanent bases, here in the Commonwealth and in other jurisdictions where some of the Joint Utilities' utility affiliates operate. Their collective experience is that dynamic pricing for residential customers tends to have low participation, and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those utilities' experiences, all of the Joint Utilities agree that a utility should consider some or all of the issues discussed in this section before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Utilities further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.

II. Scope of the Dynamic-Pricing Section

This section addresses dynamic pricing for residential customers. It defines dynamic pricing and provides summaries of the Joint-Parties utilities' experiences with dynamic-pricing offerings for residential customers. This section further provides items to consider concerning dynamic pricing, including rate structures, costs and benefits to customers and utilities, possible eligibility criteria for participating in dynamic pricing, educational needs of residential customers who participate in dynamic pricing, and a number of other relevant considerations.

III. Definition of Dynamic Pricing

Dynamic pricing refers to pricing that varies according to the time at which the energy is consumed. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to a customer via time-based rates or tariffs. There are several different kinds of dynamic pricing.

A. Time of Use or Time of Day

TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing period may change seasonally, as well; for example, a summer-peaking utility may have summer TOU periods and different non-summer TOU periods. The rates associated with each period might also change seasonally.

TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

DYNAMIC PRICING

B. Critical-Peak Pricing ("CPP")

There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally lacking in dynamism as TOU rates.

Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR")

PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than the baseline amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

D. Real-Time Pricing ("RTP")

RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

IV. Utilities' Experience with Dynamic Pricing

Several of the Joint Utilities have experience with dynamic pricing, as described below. The Joint Utilities have also assembled a collection of the dynamic-pricing rates currently available to residential customers in Kentucky (see Appendix B), as well as a collection of dynamic-pricing rates the Joint Utilities' utility affiliates in other jurisdictions offer to residential customers (see Appendix C).

A. Duke Energy

Generally, Duke Energy offers residential TOU or TOD pricing in which electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year. Prices paid for energy consumed during these periods are pre-established and known to consumers in advance, allowing them to vary their usage in response to such prices, manage their energy costs by shifting usage to a lower cost period, or reduce their consumption overall.

Duke Energy's Carolina utilities have offered voluntary residential TOU pricing rates in North Carolina and South Carolina for a number of years. To date, the TOU programs have generated little interest from residential customers. Duke Energy's Florida utility used to have residential TOU rates, but closed them in 2010 due to a lack of customer interest.

Duke Energy's Ohio electric distribution utility (Duke Energy Ohio) has conducted several pilot residential TOU programs since 2010. Duke Energy Ohio currently offers only one residential pilot program. Duke Energy Ohio has tried a number of pilots over the past few years to better understand what residential customers desire in TOU rate offerings. Generally, Duke Energy Ohio learned that customers desire three things: (1) an opportunity to achieve meaningful savings, which appears to translate into the ability to save approximately $5 to $20 dollars per month; (2) rate structures that had short peak periods during which customers would need to curtail their usage; and (3) rates without a lot of complexity and different pricing periods and seasons, as features such as "shoulder" periods make it more difficult to determine appropriate behaviors.

Through these pilot programs, Duke Energy Ohio learned that any successful TOU rates need to be cost-justified to potentially benefit the customer and the utility. A risk with TOU rates is the concept of "natural winners," those customers whose usage historically does not occur during peak periods, resulting in little to no shift in usage. Obviously, a customer who would not have to make any behavioral or usage changes for a TOU offering to lower his or her bill would find the offering more attractive than a customer who would have to shift usage and change behavior. Unfortunately, if no shifting of usage occurs, there will be no system savings, and essentially the utility will simply collect less revenue while incurring the same level of cost. Finally, based on Duke's experiences, residential TOU rates require a higher level of customer sophistication. Customers have become accustomed to paying average rates and have little understanding that the cost of using energy truly varies based upon when you consume it.

B. American Electric Power (Kentucky Power Company)

Kentucky Power has offered a number of traditional TOD or TOU rates on a voluntary basis for residential, commercial, and industrial customers since the 1980s with relatively low levels of participation. These service offerings generally included relatively lengthy on-peak periods with off-peak periods generally at night and on weekends. In 2010, Kentucky Power expanded the availability of its traditional time-of-use rates to larger customers up to 1,000 kW. Also in 2010, Kentucky Power introduced new time-of-day options for residential and small commercial and industrial customers which included shorter, seasonal on-peak periods as follows:

Winter:	Weekdays 7 a.m. to 11 a.m. and 6 p.m. to 10 p.m., November through March
Summer:	Weekdays noon to 6 p.m., May 15 through September 15

As of April 2014, no residential, 77 small commercial and industrial, and no large commercial and industrial customers are participating in these new offerings.

DYNAMIC PRICING

C. LG&E and KU

LG&E and KU both offer a pilot TOU rate to residential customers who have low-emission vehicles, Rate LEV. The rate's purpose is to allow customers who own plug-in electric or hybrid vehicles, or who use electric-powered home-filling stations for their natural-gas vehicles, to charge or fuel their vehicles at an off-peak rate that is less than the standard residential rate. Rate LEV has three TOU rates, the time-periods for which are different in the summer than for the rest of the year. LG&E and KU formulated the rates to be revenue-neutral compared to the standard residential rate. As of the end of May 2014, LG&E had 19 customers on Rate LEV, and KU had 5 customers on the rate.

Prior to offering Rate LEV, LG&E conducted a three-year variable-CPP pilot program, which it called its Responsive Pricing Pilot. The pilot offered three-tiered TOU rates with a variable-CPP component to a geographically targeted sample of residential and small commercial customers. Low- and medium-pricing periods had rates lower than the standard rate and made up approximately 87% of the hours in a year. CPP events could occur during high-demand hours for up to eighty hours per year, implemented at LG&E's discretion. Customers received at least 30 minutes' notice prior to CPP events, which had a rate of approximately five times that of the standard flat rate. Responsive-pricing participants received four devices to help them control their energy usage and respond to CPP events: smart meters, programmable communicating thermostats, in-home energy-usage displays, and load-control switches.

The pilot's results showed that customers consistently decreased their energy usage slightly in high-pricing and CPP periods; however, they used more energy overall throughout the summer periods compared to non-Responsive Pricing customers. Average demand reductions during CPP events varied from 0.2 kW to over 1.0 kW per participant during high-temperature periods, but those customers' demand rebounded after CPP periods ended, with a maximum average load increase of 0.8 kW. Even with participating customers' increased usage during summer months, they had an average bill decrease of 1.4% for those months.

LG&E's Responsive Pricing Pilot ended in 2010, and LG&E has removed the Responsive Pricing Pilot rates from its tariff.

D. Owen Electric Cooperative

Owen offers a variety of voluntary TOU rates for residential, small commercial, and large commercial members. Although Owen has made concerted efforts to promote its TOU rate offerings, participation is relatively low, with 11 residential, 26 small commercial, and 10 large commercial TOU accounts presently in place. Additionally, 178 of Owen's members are currently participating in a voluntary smart-home pilot that has a TOU component as part of the program. This two-year pilot, scheduled to end in late 2014, is presently in the measurement-and-verification-analysis phase.

E. Jackson Energy Cooperative

Jackson Energy has a residential Electric Thermal Storage ("ETS") TOU rate.[24] Jackson Energy has offered this rate since approximately 1984 and currently has 940 consumers on it.

V. Dynamic-Pricing Considerations

Based on the experiences of the utilities described above, the Joint Utilities present below a non-exhaustive list of items a utility may want to consider when formulating dynamic-pricing offerings:

A. Rate and tariff considerations

1. Opt-in versus opt-out. The Joint Utilities have demonstrated that only a small percentage of residential customers will opt into dynamic-pricing rates. Therefore, if a utility's goal is to have relatively high participation in an opt-in dynamic-pricing offering, it may consider offering incentives to participate; however, the cost of incentives must be weighed against the potential benefits.

2. Rate structure. The rates a utility will choose for any dynamic-pricing structure will differ depending on the goal of the dynamic-pricing program. For example, a utility seeking to create behavioral change, such as significant load-shifting, may want to create greater differences between the various dynamic rates than if the utility's goal is to send purely cost-based pricing signals. Also, a utility may want to introduce a demand component in a dynamic-pricing structure for residential customers to provide customers an incentive to decrease demand during peak periods rather than increasing customers' energy rates beyond the underlying energy cost of production.

3. Minimum contract terms. A utility may consider using a minimum contract term, such as a one-year minimum commitment, to guard against possible gaming by customers who choose to participate in dynamic pricing during months of the year when such rates will reduce their bills and then move back to standard rates during months when they will not be able to save. Minimum contract terms may also be desirable in a pilot program where a utility seeks to have longitudinal data from a stable set of customers.

4. Waiting periods between rate-switching. Another option to deter gaming is to bar a customer who stays on a dynamic pricing rate for less than a year from participating in dynamic pricing again for a set period of time (or perhaps permanently).

[24] Information about Electric Thermal Storage is available at: http://www.steffes com/off-peak-heating/ets.html.

DYNAMIC PRICING

5. Complexity and dynamism. More complex or dynamic rates create a greater risk of confusing customers and customer-service representatives. Also, dynamic-pricing rates that require customer notice, e.g., variable-CPP or RTP rates, require reliable means of communicating with customers. Providing the necessary communication channels could add cost to a dynamic-pricing program. In addition, more complex or dynamic rates could add cost to a utility's customer-information and billing systems.

6. Criteria for customers to participate in dynamic pricing. Dynamic rates may offer customers a chance to decrease their bills, but customers who do not or cannot follow the incentives may increase their bills, perhaps significantly. Therefore, a utility may want to limit eligibility for dynamic rates to customers who have a satisfactory payment history.

7. Hold-harmless trial period. A utility may want to consider offering customers a chance to test-drive a dynamic-pricing rate by holding the customer harmless relative to the standard residential rate for a limited trial period. This could allow customers to determine if they can respond to the dynamic rate's incentives without risk of financial harm, and may increase participation in dynamic pricing by removing a barrier to entry.

B. Technological considerations

1. Customer-facing technology. A utility should consider the technology a customer will need to have to participate in a dynamic-pricing rate. The amount of technology will vary depending on the rate, e.g., a TOU rate will require relatively less technology than will an RTP rate to allow a customer to respond to the rate's incentives. A utility may want to consider technology some customers already possess, e.g., smart phones, to help meet customer-facing technology needs more economically.

2. Utility technology. As noted in the previous section, more complex or dynamic rates will require relatively greater investments in utility systems to support the rates. Necessary technology upgrades could include, but not be limited to, billing-system upgrades, website upgrades, and other infrastructure improvements.

C. Customer education and marketing considerations

Most residential customers are accustomed to a single, flat, year-round energy rate. Dynamic pricing offers customers the opportunity to reduce their bills by responding to incentives to shift load from peak periods, and may help utilities reduce overall costs. For any number of those customers to move successfully to any variety of dynamic pricing will likely require a thorough customer-education effort to maximize good outcomes and ensure a positive customer experience. The means of carrying out such an effort are addressed in the Customer Education section of this report. The content of the effort will vary depending on the dynamic rate a utility chooses to deploy, but at a minimum such an effort should include information on the rate itself, opt-in or opt-out, minimum contract terms (if any), waiting periods between rate-switching (if any), criteria for participation, and the hold-harmless trial period (if any).

Customer-service representatives will also need training to ensure they can competently handle questions that dynamic-pricing may create.

D. Other considerations

1. Customer costs. In deciding what kind of dynamic pricing, if any, to pursue, a utility should consider the investments customers might have to make to participate, e.g., costs customers would have to incur to respond to pricing signals, both to receive notice of the pricing change and to adjust usage to respond to the signals. A utility should also inform customers up front about the minimum technology requirements for participating in a dynamic rate. For example, a customer might need to purchase a particular kind of thermostat or have a computer or smartphone with certain software to be able to participate in certain kinds of dynamic rates; a utility should communicate such requirements to customers up front. Also, a utility should provide customers a non-exhaustive list of possible ways to reduce their bills under any offered dynamic rate.

2. Equity considerations. Some dynamic-pricing rates may create natural winners and losers. For example, customers who are not home during normal working hours may naturally benefit from TOU rates where peak periods occur during those hours, whereas other customers who are necessarily at home during those hours and incapable of reducing usage may effectively pay a penalty for being unable to change their usage. A utility may want to take into account these equity considerations when crafting dynamic-pricing rates.

3. Economic justification. Particularly for opt-in rates, a utility may consider running a cost-benefit analysis to determine if a particular dynamic-pricing structure is likely to produce benefits to participating and non-participating customers.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Dynamic Pricing

Dynamic pricing is consistent with the Smart-Grid Investment Standard in that all dynamic pricing requires metering more sophisticated than traditional electromechanical meters, and dynamic-pricing with a variable component, such as variable-CPP or real-time pricing, requires smart meters.

Dynamic pricing is also consistent with the Smart-Grid Information Standard, which requires utilities to provide time-based-pricing information to customers to the extent it is available.

But as shown above, some of the Joint Utilities and their utility affiliates in other jurisdictions have offered residential customers (and other customers) different kinds of dynamic-pricing rates without imposition of the EISA 2007 Smart Grid Standards. Therefore, though these standards are consistent with dynamic pricing, their imposition is not necessary for utilities to create such rates. For this reason and the others addressed in this report, the Joint Utilities continue to oppose the EISA 2007 Smart Grid Standards.

VII. Conclusion

Dynamic-pricing rates can add complexity and create possible confusion for residential customers, who are largely accustomed to simple, straightforward, stable rates. But such rates can also offer customers the opportunity to reduce their bills by responding to incentives that may help utilities reduce overall costs, though some customers likely will not be able to avail themselves of the opportunity. Dynamic pricing, therefore, is not a clear-cut benefit or burden, and the Joint Utilities recommend that each utility evaluating the implementation of such rates carefully consider some or all of the issues discussed in this section. The Joint Utilities further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval, a position that is consistent with the Joint Utilities' prior testimony in this proceeding.

VIII. AG Comments

The Attorney General adopts all of the positions CAC has asserted in this report regarding dynamic pricing. Additionally, utility industry results for dynamic pricing or time of use (TOU) rates for residential customers are mixed, at best. The Kentucky PSC should never require mandatory TOU rates; rather, such rates should always be no more than an option for ratepayers. Many residential customers are not in a situation where they can make effective use of TOU – most of them work schedules that return them to home during on-peak times. As such, much if not most of their consumption cannot be curtailed to off-peak times. Imposition of mandatory TOU rates carries the potential of negative health impacts, or even more life-threatening conditions, from inclement weather -- especially among the elderly, those with medical-related energy needs, the poor,[25] or the infirm. Time-of-use rate plans require a certain degree of sophistication as well as flexibility to be able to take advantage of off-peak savings. Moreover, those customers seeking to control their bills may limit their usage, to their own detriment. Alternatively, if incapable of modifying their usage, customers continuing normal

[25] *See, e.g.*, Alexander, Barbara, Smart Meters, Real-time Pricing, and Demand Response Programs: Implications for Low Income Electric Customers (May 2008), available at: http://www.pulp.tc/Smart_Meter_Paper_B_Alexander_May_30_2007.pdf); Brockway, Nancy, Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers, NRRI 08-03 (February 13, 2008), available at: www.nrri.org .

usage patterns during on-peak hours could confront bills that are so costly as to lead to increased frequency of cut-offs for non-payment.

IX. CAC Comments

CAC's position is that low-income advocates are especially concerned about the potential impact on low-income customers who typically do not fully understand the complexities of dynamic pricing or lack the technology to fully take advantage of such rates, which could inadvertently result in higher bills for those customers. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

CAC further believes:

- There is no reason, at this time, to ever require that customers participate in dynamic pricing for any reason.
- Dynamic rates could especially impact senior citizens and customers with low-incomes who work non-traditional shifts. A utility must take into account these equity considerations when crafting dynamic-pricing rates.
- A utility should be able to verify that non-participating customers will not be harmed or bear any costs associated with their decision not to participate.

DISTRIBUTION SMART-GRID COMPONENTS

Distribution Smart-Grid Components

I. Executive Summary

The Joint Utilities have deployed smart technologies in their respective distribution systems as those technologies have demonstrated value or otherwise been determined to be advisable. Certain utilities describe the current state of their distribution smart-technology components in this section. This section also describes available smart-grid components for distribution systems, breaking those components into four categories: switches and valves, voltage stabilization, meters, and communications infrastructure and systems. The Joint Utilities further address three topics (and items related to those topics) utilities might consider when evaluating potential distribution smart-grid investments: technological obsolescence, prepaid metering, and remote connection and disconnection of utility service. Finally, the Joint Utilities address the effect the EISA 2007 Smart-Grid Investment Standard would have on utilities' ability to deploy distribution smart-grid technologies in a rational way, and recommend again that the Commission not adopt the standard, relying instead on the Commission's ample existing review authority concerning base rates, CPCNs, and non-base-rate recovery mechanisms.

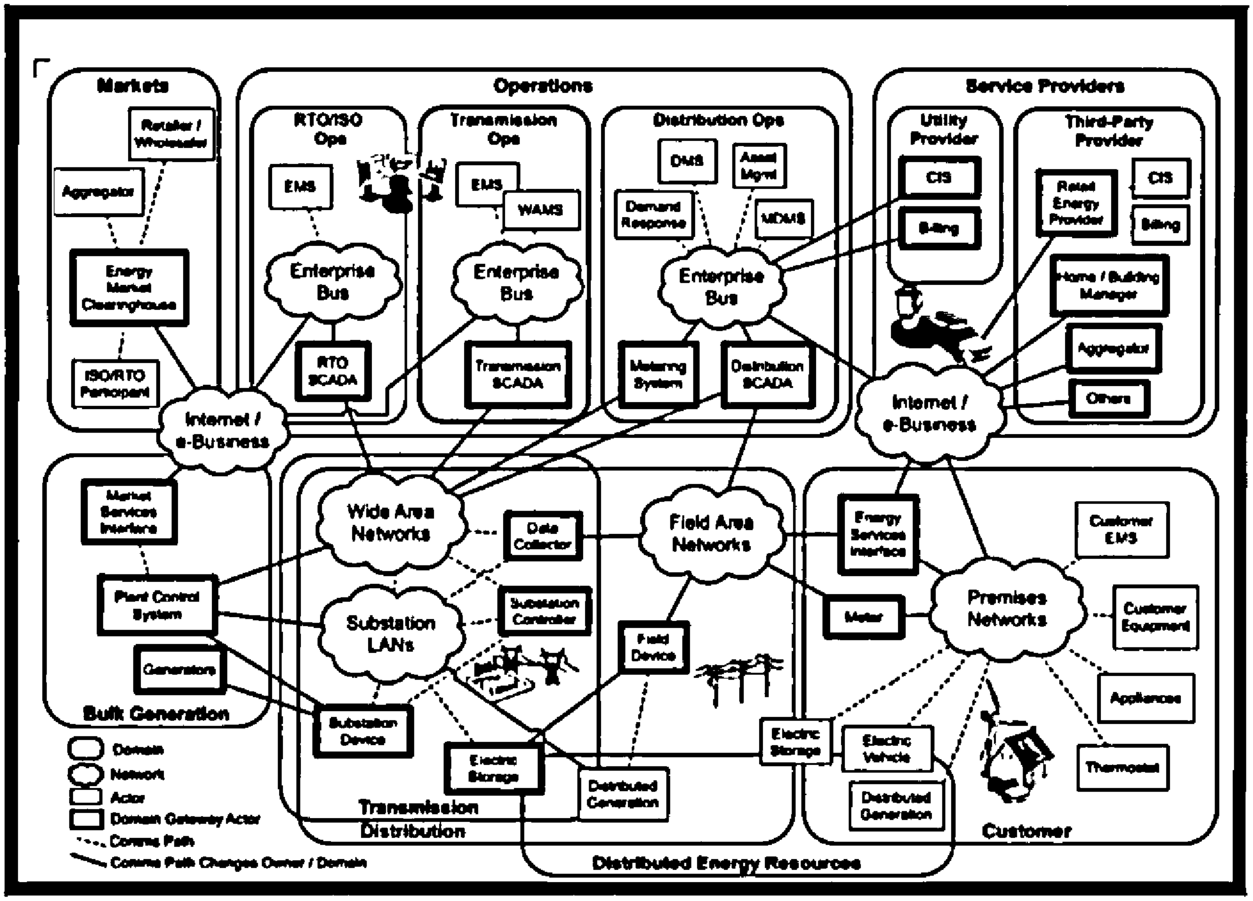
II. Scope of the Distribution Smart-Grid Components Section

This section addresses smart-grid technology for electric and gas utility distribution systems, providing a catalog of currently available smart-grid technologies for such systems and addressing several related issues, namely (a) the challenge of technological obsolescence, (b) prepaid metering, and (c) remote connections and disconnections.

This section does not address smart-grid technology in transmission, generation, or customer-facing applications, e.g., in-home displays for residential customers. Therefore, using the terminology of the National Institute of Standards and Technology diagram below, this section addresses only components in the distribution and distribution-operations domains:[26]

[26] *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0* at 43 (available at http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf).

DISTRIBUTION SMART-GRID COMPONENTS



III. Joint Utilities' Current Deployments of Distribution Smart-Grid Technologies

All of the Joint Utilities deploy some form of distribution smart-grid technology. Each utility provided information concerning its particular deployments in response to the Commission Staff's First Request for Information in this proceeding.[27] Also, the Kentucky Smart Grid Roadmap Initiative's "Smart Grids in the Commonwealth of Kentucky: Final Report of the Kentucky Smart Grid Roadmap Initiative" provides summaries of the utilities' smart-grid-related deployments as of 2012.[28] For ease of reference, several of the Joint Utilities provide below summaries of their current deployments of distribution smart-grid technologies.

A. American Electric Power (Kentucky Power Company)

Kentucky Power has deployed AMR, Distribution Automation – Circuit Reconfiguration ("DA-CR"), Volt/VAR Optimization ("VVO"), and SCADA. AMR has been fully deployed in Kentucky Power for a number of years and provides benefits such as the efficient and timely collection of customer energy data with reduced operating costs. DA-CR and VVO technologies are not fully deployed, but Kentucky Power continues to evaluate and plan for additional

[27] In particular, please see the utilities' responses to Commission Staff Request Nos. 96-102 and 113.
[28] The Commission has incorporated the report in the record of this proceeding.

DISTRIBUTION SMART-GRID COMPONENTS

installations. Currently, there are nine distribution circuits with DA-CR technology and another nineteen being implemented. Similarly, twenty-one distribution circuits have VVO technology installed with four more under development. DA-CR and VVO installations have already demonstrated benefits to customers. DA-CR installations have improved customer reliability by reducing the duration of outages and VVO installations have provided measureable reductions in the demand for energy. In addition, SCADA installations provide the communication infrastructure to support DA-CR and VVO technologies. Approximately thirty-eight percent of distribution substations and approximately ninety percent of transmission substations are equipped with SCADA.

B. Duke Energy Kentucky

Duke Energy Kentucky has installed four self-healing teams (described in greater detail in Section IV.A.) as part of its normal reliability improvement process, when and where appropriate. Duke Energy Kentucky considers the self-healing technology to be smart-grid-related technology, as it includes two-way communications with distribution-system devices allowing for remote operations, although its functions are typically performed automatically. An efficiency benefit to the utility is that the self-healing team is able to automatically identify the section of the circuit where the fault occurred, which results in less assessment time from crews by being able to travel directly to a problem as opposed to patrolling the entire circuit to find the problem. Self-healing teams are also a benefit to customers because they reduce the duration of a sustained outage. Additionally, Duke Energy Kentucky uses some AMI meters that were installed as part of a pilot of a two-way automatic communications system ("TWACS") about eight years ago. Duke Energy Kentucky decided not to proceed with a large-scale deployment of this technology.

C. LG&E and KU

LG&E and KU have deployed four SCADA systems (KU, LG&E electric, LG&E gas, and downtown Louisville), and have installed about 90,000 AMR meters (electric and gas) across their service territories. LG&E is currently deploying approximately 1,500 advanced meters and related infrastructure in its downtown Louisville network as part of a project to gather enhanced engineering information for network planning. Also, LG&E and KU recently applied to the Commission in Case No. 2014-00003 to deploy up to 10,000 advanced meters and related infrastructure through its proposed Advanced Metering Systems customer offering.

D. Jackson Energy Cooperative

Jackson Energy offers prepaid metering as a voluntary option to its consumers.

Participation in prepaid metering allows consumers to monitor their daily usage and take steps to conserve energy. Research into similar prepaid metering programs by other utilities indicated that consumers reduced their usage by as much as 12 percent. Initially Jackson Energy saw energy reductions of 16 percent by prepaid metered consumers compared to their non-prepaid-metered neighbors. Over time the percentage has dropped to 8 percent. Again, these reductions resulted from customers more carefully monitoring their usage, not from any function of the prepaid meters.

Additional benefits to customers of prepaid metering include no deposit, no late charges and no disconnect or reconnect fees.

Jackson Energy currently has over 3,000 prepaid-metered consumers.

Jackson Energy was able to implement prepaid metering by utilizing the AMI system that was already in place.

E. Owen Electric Cooperative

Since 2009, Owen has been engaged in pilot projects that focused on the installation, study, reporting, and advancement of several budding smart-grid technologies. The U.S. Department of Energy ("DOE") provided a grant, managed by Kentucky Department for Energy Development and Independence ("DEDI") within the Energy and Environmental Cabinet, for Owen's first two pilots. The first pilot focused on the self-healing of an area of the system that was far from a service center and had 17 miles of distribution exposure to 900 members. Through smart-switch automation, an alternate feeder from the same source has reduced member interruption duration times by 78% during "healing" events since the fall of 2011. A "Beat the Peak" program was the second pilot in the state grant. This project was designed to gauge participants' willingness to voluntarily reduce electrical consumption during system peaks. Participants were furnished in-home devices that signaled system peak load conditions. Members were alerted, via text messaging or email, of an approaching system peak.

The second grant was through the DOE and administered by the National Rural Electric Cooperative Association. The projects were diverse in nature and were chosen to continue Owen's two-fold smart-grid mission. This mission is to provide new energy-management tools to members in the face of increasing environmental regulation (retail costs) of the power industry, combined with a measured improvement in both the quality and reliability of the power delivered.

The results and ongoing efforts are as follows:

1. SCADA system upgrade – The 1987 vintage SCADA system was replaced by a system equipped with advanced substation and downstream automation capabilities. The self-healing projects have enhanced the performance of the advanced SCADA technology Owen has installed.

2. In addition to increased situational awareness provided by the SCADA upgrade, there are two other key benefits Owen is learning to utilize. The first is substation-device-fault-event information, such as fault type and magnitude, which Owen can now utilize to direct field personnel to specific trouble sites. This information has also shown benefit in allowing the detection of downstream-device operations and manually detecting an

outage prior to member outage calls being received. This capability, when leveraged with Owen's existing Outage Management System ("OMS") and OMS-AMI interoperability, directly benefits Owen's membership with a higher level of confidence and responsiveness. Secondly, Owen has begun utilizing substation-bus-voltage reduction in coordination with its engineering model and verified end-of-line voltages from its AMI system to execute an initial Conservation Voltage Reduction program at no additional cost. This has allowed Owen to reduce its peak demand charges and operate more cost effectively for its membership. Owen's voltage-reduction capabilities were advantageous during a recent system-wide emergency conservation request to reduce energy utilization for the overall electrical grid stability.

3. Smart Home – The pilot project was launched in 2012 and serves 178 member homes. It is presently in the measurement-and-verification ("M & V") phase and will come to a close in 2014. In just the few short years since the pilot was begun there have been significant changes in advanced meter technology and the availability of new member engagement tools such as smart phones, smart applications, Green Button,[29] and commercially available smart thermostats. Future deployment of a Smart Home will reflect these changes and will be dependent on the results of the M & V phase.

4. Volt-Var Optimization – A substation and its associated feeders have been chosen for analysis of the impacts that advanced voltage and Var control would have on a distribution system. Demand reduction, loss reduction, improved voltage regulation, and reactive power management are planned outcomes.

5. Communications System Upgrade – Owen discovered at the outset of its Smart Grid endeavors that robust communication systems are vital. A major upgrade that incorporated fiber optic paths to critical points has been put into place. The increased communication capacity has improved Owen's automated metering and SCADA capability and is necessary for future distribution automation projects.

Another self-healing project improves reliability by providing emergency backup to a large power account with critical operations in northern Kentucky. The self-healing systems saved Owen's members considerable investments by eliminating the need for on-site backup generation.

Additionally, Owen recently implemented a meter-data-management system that enables members to view their usage via a member portal. Owen also recently gained Commission

[29] *See* http://www.energy.gov/data/green-button.

approval to offer a prepaid-metering program to its members. By offering members access to their usage in a more timely and convenient manner, Owen believes that members will be better equipped to manage their energy consumption.

F. Jackson Purchase Energy Corporation

Distribution Automation. Jackson Purchase Energy Corporation ("JPEC") operates a Distribution Automation scheme around the Kentucky Oaks Mall that includes commercial and residential areas. This switching scheme involves multiple reclosers located in substations and tie points on feeder circuits, all communicating with each other by the use of fiber optics. When the system senses a fault, reclosers communicate with each other and operate to isolate the fault to a small line section instead of an entire feeder. This operation may mean isolating the end of a line or transferring load from one substation or feeder to another, thereby isolating the faulted line section. This information is then sent to JPEC's OMS system and dispatchers know instantaneously that a service interruption has occurred and a crew needs to be dispatched.

Voltage Conservation. Using SCADA and AMI, Jackson Purchase Energy can lower the voltage profile of most of its circuits by controlling circuit regulators or substation voltage, which in turn reduces JPEC's system peak. Using system modeling software, JPEC can determine which meters on a circuit need to be monitored for end of line voltage. Then, using the AMI system, end-of-line voltage is reported back to the SCADA system and analyzed by a program that then sends a command to the circuit regulators to either increase or decrease voltage to the circuit. The program requires a forecasted load input and will automatically initiate or terminate when JPEC's system load falls within a certain percentage of the forecasted load.

G. Natural-gas local distribution companies (LDCs)

The three natural-gas-only LDC members of the Joint Utilities have implemented meters that can be read remotely. Each has some difference in circumstances. None of the three LDCs has any current plans to implement AMI or to go beyond the automated meter reading equipment plans below.

Delta Natural Gas for many years has had 100% remote meter reading so that meter readings can be gathered efficiently with devices installed on each meter that transmit meter reads for use in the company's billing system for calculating and rendering billings to customers.

Columbia Gas obtained Commission approval, as a part of its recently concluded rate case, to add meter reading devices on 100% of its meters.[30] The devices will be similar to Delta's equipment, and the installation is scheduled to be completed in 2014.

Atmos Energy has transmitter devices on about 500 of its Kentucky meters as a pilot program. This is the Sensus FlexNet System, which uses a transmitter installed on existing

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[30] *In the Matter of: Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates for Gas Service*, Case No. 2013-00167, Order (Dec. 13, 2013).

meters to collect and transmit hourly meter readings from the gas meter to a central data base. The system uses communications devices installed on towers. Meter readings are utilized for customer billing and automation of service orders that require the collection of a meter reading to fulfill various customer service requests. One meter reading per day is entered into the customer account record. The daily readings are used to satisfy requests to collect a reading for move in/move out and other meter reading investigation activities. They are also viewable by the customer through Atmos Energy's online account center, where daily usage is graphically displayed for any billing period in question. Also displayed is the daily high, low, and average temperature for comparison.

IV. Overview of Distribution Smart-Grid Components

The Joint Utilities' view is that the distribution smart-grid consists of four basic categories of intelligent electrical devices: switches and valves, voltage stabilization, meters, and communications and SCADA. Members of the Joint Utilities provide an overview of each category of components below by describing their experience with the technology:

A. Switches and valves (Duke Energy)

Duke Energy has deployed self-healing technology as part of its grid modernization efforts in other states as well as Kentucky. Self-healing technology, which provides an immediate benefit of increased system reliability, uses distribution line power devices such as switches, programmable reclosers, and circuit breakers that are automated and thus capable of communicating via an intelligent control system. The control system, communications system, and power line devices all work together as a "team," collectively serving to identify, communicate, and isolate the portion of the distribution system affected by a fault or other problem, thus minimizing the impact to others. When a fault occurs and a substation locks out, the self-healing team locates the fault, isolates the fault by opening switches immediately upstream and downstream of the fault, and restores power to the sections of the grid not affected by the fault.

B. Voltage stabilization (Kentucky Power)

Kentucky Power has installed VVO technology on twenty-one distribution circuits with four additional installations in progress. VVO installations in Kentucky were preceded by installations at several of Kentucky Power's affiliate companies in Ohio, Indiana, and Oklahoma, with proven results to reduce peak demand and energy consumption for customer loads, as well as delivering reliability benefits. VVO is a smart-grid technology because it allows the distribution grid to automatically detect and react to voltage conditions along the entire length of a distribution circuit and optimize around a more narrow voltage range. A "real world" example of VVO's capability and reliability benefit was recently showcased when the Commonwealth was hit with record cold temperatures in January 2014. Kentucky Power was able to remotely operate distribution circuits equipped with VVO technology to avoid circuit overloading and rolling outages.

DISTRIBUTION SMART-GRID COMPONENTS

C. Meters (Duke Energy)

Duke Energy's definition of a smart grid or grid modernization includes the deployment of a fully advanced metering system that provides two-way communications between the meter and the back office data systems. Communications from the meter include usage data at regular intervals, off-cycle meter reads, theft or tamper alarms, and power-quality alarms. Communications to the meter include meter-program updates and disconnection or reconnection commands. Additionally, this new two-way-communication path for AMI meters can allow for new customer products and services in the future. For those reasons, Duke Energy considers AMI meters to be integral smart-grid components.

Duke Energy has also deployed AMR meters in various territories to facilitate meter reading across the board or for hard-to-access locations. Those meters are not integrated into the AMI back office data systems and do not have the same functionalities as AMI meters; therefore, Duke Energy does not consider AMR meters to be a part of the smart grid.

D. Communications and SCADA (LG&E-KU)

LG&E operates a secondary network system in the downtown business district of Louisville, KY referred to as the LG&E Downtown Secondary Network ("DTN"). There are five different networks in the DTN system, which together comprise 189 vaults, 408 transformers or network protectors, and 27 primary circuits served from three substations. The distribution system provides service to utility customers using radial distribution circuits, interconnected on the secondary side of the distribution transformers through high-current secondary breakers called network protectors. Each of the networks is designed to withstand a single-circuit outage with sufficient capacity on the remaining circuits and transformers to keep all customers in power.

LG&E's DTN has a network-protector-automation system that enables real-time monitoring of loads, critical equipment, vault information, and remote-control operation of network-protector switches.

Before LG&E installed the network-automation system, there was no monitoring or control capability built into the secondary network system. In the new DTN system, microprocessor relays in the network protector devices provide basic information, including voltage, load, and protector breaker position. The automated system includes a full complement of sensors, providing insight into the status of vaults, including vault temperature, transformer temperature, water level, fire indication, and load flows for vault services and to the network grid. Having the ability remotely to obtain information about the vaults' status and to operate protector breakers should enhance the safety of LG&E's workers, who otherwise would have to enter the vaults to perform those functions.

The DTN's front end is a standalone SCADA system. This system contains a user interface with maps and screens detailing the network protectors and vaults, records status information from the microprocessor relays and sensors, and provides system operators with real-time status and alarm information and automatically notifies operating personnel of the same through email, phone calls, or text messaging.

In sum, the combination of all the smart technologies LG&E is installing in the DTN should enhance the safe and reliable operation of the system, and position it well to provide additional capabilities in the future, such as asset management and engineering, modeling, and analysis of the DTN.

V. Distribution Smart-Grid Investment Considerations

A utility considering investments in distribution smart-grid technologies might consider the following non-exhaustive list of factors that could impact which technologies to deploy:

A. Obsolescence of distribution smart-grid technologies

A possibly significant consideration when deploying any technology, but particularly when deploying new and rapidly developing technologies, is technological obsolescence. In the high-tech world that encompasses smart-grid technology, vendors can quickly go out of business. Those that survive often move on to new versions of products or entirely new products, ceasing to support previous products in the process. In either event, high-tech products can rapidly become orphan technologies, leaving those who have invested in the technologies with difficulties in continuing to support and maintain them.

In addition to the obsolescence risk the normal high-tech business cycle creates, a utility's own changing needs and the changing demands of its customers may effectively render obsolete otherwise serviceable technologies. By way of analogy, the formerly cutting-edge flip-phone remains an entirely serviceable technology for making phone calls on modern cellular networks; however, the more recent advent of truly high-speed wireless data has rendered such phones obsolete for many people who need or desire to conduct data-intensive business functions remotely, including e-mail and videoconferences. The same kinds of technological advances could render some distribution smart-grid components effectively obsolete before the end of their useful lives as consumers and utilities increasingly expect more from their systems, particularly in terms of data, than previous generations of technology could provide.

In conducting their cost-benefit analyses, utilities might consider not only how the future obsolescence of smart technologies impact costs and benefits, but also how foregoing the benefits of deploying smart technologies today creates opportunity costs for themselves and their customers. Using the same cell-phone analogy discussed above, continuing to use a flip-phone while a better, smarter phone is available results in foregone benefits—an opportunity cost—the phone user should consider when deciding whether to upgrade to a smarter phone.

Another aspect of technological obsolescence a utility might consider is the ongoing viability of currently deployed meters. For example, if electromechanical meters are no longer available from domestic manufacturers (which the Joint Utilities believe to be true), it will be

DISTRIBUTION SMART-GRID COMPONENTS

more difficult and possibly more costly to maintain and repair such meters. Such costs might make it more economical to invest in smart meters as replacements for some utilities.

Therefore, a utility might consider both the obsolescence issue (for both existing meters and potential replacement technology) and the 'loss of benefits' issue when considering distribution smart-grid investments.

B. Prepaid metering

Prepaid metering is by no means a new technology: General Electric offered prepaid electric meters as early as 1899.[31] But the significant advances of smart technology have greatly improved the capabilities of prepaid meters. Prepaid metering using smart meters can provide benefits for customers, eliminating the need for customer deposits, significantly reducing or eliminating connection and disconnection charges, making reconnection nearly instantaneous upon the receipt of funds (which can be done online), and providing another payment option for customers. But prepaid metering could require a change to the process by which community action agencies and other providers of utility assistance payments provide service to their constituents, as well as changes to the requirements of the federal or other aid programs the agencies administer. It could also require changes to current regulations and tariff provisions concerning disconnection and reconnection of service. But as noted above, smart-meter technology would provide the benefit of faster and easier reconnection of service whenever such assistance is provided to customers in need. Therefore, a utility might consider the costs and benefits of prepaid metering when considering distribution smart-grid investments.

C. Remote connection and disconnection of utility service

Remote connections and disconnections require AMI, i.e., two-way communications between a utility and its meters. The ability to connect or disconnect remotely customers' service is therefore a capability a utility might consider when analyzing possible distribution smart-grid investments.

Remote connection and disconnection capability has numerous benefits: decreasing operating expense by eliminating the need to send personnel to disconnect and reconnect service (which must be netted against higher meter costs and possibly increased meter-maintenance costs for smart meters); increasing safety for utility employees; reducing charge-offs of bad debt by more rapidly and broadly shutting off service for non-payment (in accordance with Commission regulations only), which reduces the bad-debt expense other customers ultimately must bear; reducing reconnection times, which would speed the effect of utility assistance payments; and providing the ability to respond more rapidly to inactive accounts and accounts with high turnover, such as apartments.

On the other hand, because remote disconnection capability would permit a utility to disconnect all eligible customers rather than the fraction of such customers the utility can

[31] *See* http://www.watthourmeters.com/history.html; http://www.google.com/patents/US667138; http://www.watthourmeters.com/generalelectric/trw-pp.html.

disconnect today due to resource constraints, some customers who might avoid disconnection (at least for a time) today may not avoid disconnection if their utility installed smart meters. But as noted above, the ability to disconnect a customer rapidly allows for the ability to reconnect the customer rapidly, which means the customer would experience the benefit of shorter periods of time without service. Another benefit of remote connect-disconnect capability is ensuring that the customer does not have the ability to amass an even larger debt to the utility (sometimes compounded by reconnection charges, late-payment fees, and additional deposit requirements). And as noted above, customers, not utilities, are ultimately the ones who must bear bad-debt expense, so minimizing the amount of bad debt has a beneficial impact on rates for all customers.

VI. EISA 2007 Smart-Grid Investment Standard and Distribution Smart-Grid Components

The Joint Utilities continue to oppose adopting the Smart-Grid Investment Standard in Kentucky. Most utilities' investments in distribution smart-grid components to date have been, and are likely to be, incremental, not wholesale replacements of entire categories of existing components with smart components. But taken literally, the Smart-Grid Investment Standard would require every utility to demonstrate to the Commission, presumably through an application process, that any proposed investment in non-smart-grid technologies—no matter how small—would be superior to an investment in comparable smart-grid technologies. This would needlessly multiply proceedings before the Commission and likely harm customers due to increased regulatory compliance costs.

The incremental approach most utilities are taking to making most investments in distribution smart-grid technologies allow the utilities to submit projects to the Commission in many forms. Utilities could submit these investments for Commission review in a base-rate case, a CPCN application, or through a non-base-rate mechanism proceeding. The Commission has existing authority in all of these cases to conduct a review and ensure prudence of the utility investments and expenditures.

VII. Conclusion

Although distribution smart-grid components can provide benefits to customers and add value to utilities' distribution systems, there are a number of items utilities might consider before investing in such systems, including items related to technological obsolescence, prepaid metering, and remote connection and disconnection of utility service, all of which can impact customers. But adding another layer of regulation, i.e., the Smart-Grid Investment Standard, to the Commission's already robust oversight authority is not necessary to ensure utilities make only prudent investments; rather, the Commission's existing authority concerning base rates, CPCNs, and non-base-rate recovery mechanisms is sufficient to protect customers while maintaining regulatory efficiency.

VIII. AG Comments

The Attorney General has no additional comments with regard to this chapter.

DISTRIBUTION SMART-GRID COMPONENTS

IX. CAC Comments

Though CAC is open to the possibility of a fair and limited risk process for prepaid metering, it has previously opposed such processes and continues to be concerned. It is CAC's belief that prepaid metering will increase the number of customers facing disconnection and, therefore, the number and duration of families and children exposed to lack of heat in winter or cooling in summer. Recent extreme temperatures in 2014 serve to illustrate the risk. This is especially of concern for households where medical conditions such as asthma can be exacerbated by extreme temperatures. Any prepaid metering program should be very carefully examined and designed in close collaboration with community action agencies or other local providers who work regularly alongside customers with low-income. It should take into consideration households affected by a medical condition and or the homes of seniors and the disabled.

CAC is also concerned that the ability to remotely disconnect a customer could significantly increase the frequency of disconnections, especially among vulnerable populations such as customers with low-incomes and seniors or the disabled. Increased disconnections have been seen in markets where smart grid technology has been deployed. Although there may be some benefits such as a faster reconnect process, CAC is concerned that methods of rapid payment to facilitate such reconnection (internet access, credit cards for phone payment, etc.) are not universally available for the customers at risk of such a disconnection. This issue, because it poses a health threat to vulnerable customers left in extreme cold or heat by a remote or automated disconnection, is perhaps of the greatest concern to CAC of all smart grid issues. Further exploration of this issue is warranted to ensure consideration of special circumstances.

CYBER-SECURITY

Cyber-Security

I. Executive Summary

Cyber-attacks are increasing in intensity and sophistication. As recent breaches of large retailers' payment systems have demonstrated, even well-designed and -built cyber-defenses can be overcome when attackers discover weak links in systems and exploit them.

The Joint Utilities are well aware of the cyber-security threat and take it seriously. Indeed, it is in the utilities' best interests to thwart cyber-attacks; all stakeholders' interests are completely aligned on this issue. So although no cyber-defense is perfect and breaches may occur, Kentucky's utilities are working to prevent and defeat cyber-attacks that threaten their systems and the integrity of their and their customers' data.

Some members of the Joint Utilities are subject to mandatory cyber-security standards to protect the Bulk Electric System. As described below, the entities responsible for enforcing these standards have been vigilant, as have the subject utilities, and the penalties utilities might have to pay for violating the standards are substantial: as much as $1 million per violation per day.

There are also several voluntary cyber-security frameworks and guidelines that Kentucky's utilities consult when designing and implementing their cyber-defenses. These industry standards have the benefit of evolving relatively quickly to help utilities adapt to ever-changing cyber-attack strategies and methods.

In view of the force of existing cyber-security standards, utilities' inherent interest in defeating cyber-attacks, and utilities' use of voluntary cyber-security frameworks and guidelines, the Joint Utilities recommend against implementing any state-level cyber-security regulation or enforcement.

II. Scope of the Cyber-Security Section

This section addresses the mandatory standards with which some Kentucky utilities must comply, as well as voluntary frameworks and guidelines some utilities have adopted, to guard against unauthorized access into utilities' smart-grid-related systems, including unauthorized access to information utilities gather from customers using smart-grid technology. This section addresses cyber-security primarily related to smart-grid components, not utility cyber-security generally. For example, this section does not address the security measures for utilities' websites, which would exist even if utilities did not deploy smart-grid components.

The scope of this section is also separate and distinct from the Customer Privacy Section of this report, which addresses rights and responsibilities concerning Kentucky utilities' gathering and authorized use of customer information, including customers' and other parties' access to such information. This section addresses only safeguards against unauthorized access.

CYBER-SECURITY

III. Cyber-Security Standards Already in Force

The mandatory cyber-security standards in place today are the Critical Infrastructure Protection ("CIP") Standards drafted by the North American Electric Reliability Corporation ("NERC"), approved by the Federal Energy Regulatory Commission ("FERC"), and administered and enforced by NERC and its regional entities, including the SERC Reliability Corporation ("SERC"). (SERC's jurisdiction covers all of Kentucky except its easternmost portion, which is under the jurisdiction of the ReliabilityFirst Corporation.)

Eight of NERC's nine mandatory CIP Standards (version 3) address cyber-security:

- CIP-002: Requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System.

- CIP-003: Requires Responsible Entities to have minimum security management controls in place to protect Critical Cyber Assets.

- CIP-004: Requires personnel with access having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including contractors and service vendors, to have an appropriate level of personnel risk assessment, training, and security awareness.

- CIP-005: Requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter.

- CIP-006: Addresses implementation of a physical security program for the protection of Critical Cyber Assets.

- CIP-007: Requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s).

- CIP-008: Ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets.

- CIP-009: Ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices.[32]

[32] Quoted from http://www.nerc.com/pa/CI/Comp/Pages/default.aspx. This section does not address NERC CIP-001, which standard concerns sabotage reporting, not cyber-security explicitly.

CYBER-SECURITY

These standards mandate many industry-best-practice processes to protect the computer networks associated with assets considered to be critical to the bulk electric system. In response to the CIP Standards, the entire electric industry has implemented extensive security enhancements for the computer networks associated with critical bulk-electric-system assets, including smart-grid components. Many utilities, including members of the Joint Utilities, have also implemented extensive internal compliance programs to help ensure their compliance with the CIP Standards, often including significant oversight and involvement from their senior leadership and internal self-assessments to test the quality of their implementation.

NERC and its regional entities apply the CIP Standards to all FERC-jurisdictional entities, including all of the electrical-utility members of the Joint Utilities except the distribution cooperatives. The penalties for violating the standards can be severe: NERC and its regional entities may impose fines on a utility of up to $1 million per violation per day, and they may find a utility has committed more than one violation each day.[33]

IV. Voluntary Cyber-Security Frameworks and Guidelines

In addition to the mandatory standards above, the Joint Utilities' electric-utility members are aware of the following non-exhaustive list of voluntary cyber-security frameworks and guidelines, which various Kentucky electric utilities consult when considering cyber-security:[34]

A. National Institute of Standards and Technology Interagency Report ("NISTIR") 7628, "Guidelines for Smart Grid Cyber Security"

The Guidelines for Smart Grid Cyber Security were developed by the Cyber Security Working Group of the Smart Grid Interoperability Panel, a public-private partnership launched by the National Institute of Standards and Technology. These voluntary guidelines address four broad cyber-security topics:

- Cyber Security Strategy. Provides a cyber-security strategy for the smart grid and the specific tasks within the strategy.
- Logical Architecture. Provides a composite high-level view of smart-grid actors and includes an overall logical reference model of the smart grid, as well as information on each of the 22 logical-interface categories in the smart grid.
- High Level Security Requirements. Provides high-level security requirements for each of the smart grid's 22 logical-interface categories.

[33] Sanction Guidelines of the North American Electric Reliability Corporation at 5-7 (available at: http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_4B_SanctionGuidelines_20121220.pdf).
[34] The Joint Utilities are aware of other cyber-security-related frameworks, such as the U.S. Department of Energy's Electricity Subsector Cybersecurity Capability Maturity Model ("C2M2") and the SANS Institute's Top 20 Critical Security Controls ("SANS 20"); however, the Joint Utilities are not addressing them in this report because such cyber-security maturity models and control proposals do not primarily concern the smart grid.

- Cryptography and Key Management. Identifies technical cryptographic and key management issues across the scope of systems and devices found in the smart grid, along with potential alternatives.[35]

B. National Rural Electric Cooperatives Association ("NRECA") and Cooperative Research Network ("CRN"), "Guide to Developing a Cyber Security and Risk Mitigation Plan"

The Cooperative Research Network has developed a set of tools that compose the "Guide to Developing a Cyber Security and Risk Mitigation Plan." The purpose of the tools is to enable cooperatives to strengthen their security posture and chart a path of continuous improvement. The tools are:

- A Guide to Developing a Cyber Security and Risk Mitigation Plan. As part of the CRN Regional Smart Grid Demonstration, CRN created a guide to enhance security at the co-ops participating in the demonstration as they acquire and deploy grid components and technologies. Written for co-ops participating in the demonstration, the Guide can be used by any utility.

- Cyber Security Risk Mitigation Checklist. A list of activities and security controls necessary to implement a cyber-security plan, with rationales.

- Cyber Security Plan Template. Co-ops can use this form to create their own cyber-security plan.

- Security Questions for Smart Grid Vendors. CRN is encouraging co-ops to include these questions in their RFPs for smart-grid components. The questions are designed to facilitate a frank and open dialogue on cyber-security with those who make and sell components.

- Interoperability and Cyber Security Plan. The Interoperability and Cyber Security Plan ("ICSP") was the first deliverable produced for the Department of Energy, funded by a matching grant. The ICSP examines risk management, identification of critical cyber-assets, and electronic security perimeters, among other issues.[36]

V. Current Cyber-Security Standards, Guidelines, Oversight, and Enforcement Are Sufficient

As shown above, there are already adequate requirements, enforcement mechanisms, and guidelines concerning cyber-security for utilities' smart-grid systems. Indeed, the recent "Cyber Security Risk Assessment and Risk Mitigation Plan Review for the Kentucky Public Service Commission" shows that responsible agencies are conducting oversight activities even for

[35] http://www.nist.gov/smartgrid/upload/nistir-7628_total.pdf.
[36] https://groups.cooperative.com/smartgriddemo/public/CyberSecurity/Pages/default.aspx.

electric utilities not subject to mandatory cyber-security requirements.[37] Therefore, additional cyber-security requirements, oversight, and enforcement at the state level are not necessary.

Worse than unnecessary, additional prescriptive requirements in this area could prove to compound rather than mitigate cyber-threats. Cyber-attacks and the threat they pose are constantly evolving, making cyber-security regulatory requirements, particularly ones that lock utilities into particular technologies or protocols, potentially dangerous. Utilities must have sufficient flexibility to adapt to threats as they develop and change; regulatory strictures constraining that flexibility could prove to be fatal straitjackets, not safeguards. Additional regulatory mandates might diminish utilities' ability to make their best risk-mitigation decisions to prioritize IT security resources. Instead, state-level mandates could create an opportunity to push the focus of those resources to risks that utilities might consider to be very low compared to other risks.

Moreover, additional regulations and requirements may provide a counterproductive and false sense of security. No economically rational set of cyber-defenses can provide complete security from cyber-attacks, but mere compliance with a set of regulations could create a false impression of impregnability that erodes vigilance. It is in all stakeholders' interests for utilities to stay focused on defeating threats, not complying with regulations.

Another area of concern is that state-level requirements could create a completely new risk for utilities, namely a risk of rules that are inconsistent or inefficient when compared to existing federal regulation. Assuming a state rule is written differently than a federal rule, there is a possibility of inconsistent or inefficient expectations. Inconsistent rules would promote confusion, not security, and the resulting inefficiencies would result in higher costs to customers.

Finally, all stakeholders' interests—customers', regulators', and utilities'—are completely aligned concerning cyber-security; it is in no stakeholder's interest for cyber-attacks to succeed. For that reason, Kentucky's utilities strive to comply with applicable requirements and consider voluntary guidelines when implementing cyber-security measures.[38] Although some cyber-attacks may succeed no matter how robust utilities' defenses, Kentucky's utilities are working diligently to protect their systems and their customers. Therefore, additional regulation or oversight at the state level will not serve to enhance utilities' smart-grid cyber-security.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Cyber-Security

The EISA 2007 Smart Grid Investment Standard would require an electric utility, prior to undertaking investments in non-advanced grid technologies, to demonstrate that it considered an investment in comparable smart-grid technologies by evaluating a number of factors, including total costs, cost-effectiveness, and security. Cyber-security would certainly affect these three factors, but that does not support adopting the standard. Utilities already consider these factors when making investment decisions and proposals to the Commission. Moreover, as the Joint

[37] Available at: http://www.naruc.org/Publications/FINAL%20KY%20SERCAT%202013_for%20posting.pdf.
[38] Joint Utilities' utility members' responses to the Commission Staff's First Request for Information, dated February 27, 2013, Question No. 104, which address cyber-security measures the utilities have implemented.

Utilities have already argued, the Commission already possesses all the regulatory authority it needs to address these three factors, as well as all the others in the standard except one. The Joint Utilities therefore continue to oppose implementing the EISA 2007 Smart-Grid Investment Standard in Kentucky.

The Smart-Grid Information Standard does not have direct cyber-security implications. To the extent the standard would require utilities to implement smart technologies to provide customers the required information, existing investment reviews (see above) already may address cyber-security for such technologies. Cyber-security concerning the delivery of information to customers, e.g., through a web portal, is not directly related to smart-grid components, but rather is part of each utility's cyber-security for existing web sites and other customer-information-delivery systems.

VII. Conclusion

None of the Joint Utilities takes cyber-security lightly; rather, all agree that utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks. On the issue of cyber-security, all stakeholders' interests and incentives are aligned. But the Joint Utilities further agree that existing mandatory and voluntary cyber-security standards, frameworks, and guidelines are sufficient, and that adding such regulations or rules at the state level may serve to weaken rather than strengthen utilities' ability to thwart cyber-attacks by slowing their ability to adapt to the ever-changing threat; indeed, in today's threat environment, the ability to remain agile and evolve cyber-security defenses, tools, procedures and overall defensive posture is critical to a utility's ability to protect against emerging cyber threats. The cyber-security focus should be on a utility's ability to evolve with emerging threats, not on their compliance with cyber-security standards based on legacy threat profiles. A mature effective cyber-security process is one that is continuously evolving based on emerging threat intelligence and threat vectors or actions. Therefore, additional regulations or requirements at the state level are not necessary or advisable.

VIII. AG Comments

In the interest of succinctness without forfeiting emphasis, the Attorney General provides the following quotes from individuals with far more expertise on cyber security than does the undersigned.

> "There are intelligent adversaries out there and they are looking at your stuff. They are looking at it probably right now. They may not be a human doing it at this moment, but there are computers scanning your stuff right now. What takes a human a long time to do, a computer can do in a blink of an eye. Put it this way, you can scan the entire Internet, every single address, in a matter of hours if

> you have enough computers doing it, and then you can aggregate those results into one place."[39]
>
> "Cybersecurity experts glibly note that there are two types of organizations: those that know they've been hacked and those that don't."[40]

The Chairman's forum on cybersecurity and the comments of Patrick C. Miller, founder, director and President-Emeritus for the Energy Sector Security Consortium, could not have been better timed. Less than six (6) months later, on 13 June 2012, prior U.S. Defense Secretary Leon Panetta warned the Senate Appropriations Subcommittee on Defense that America faces a high risk for a "digital Pearl Harbor" by way of cyberattack. Secretary Panetta specifically referenced the nation's power grid.[41] Recent history has now demonstrated that Secretary Panetta's warning should not be taken lightly. Indeed, just in recent weeks it has been disclosed that a number of Chinese nationals have managed to "compromise" the computer network of a U.S. public utility, according to a report from the U.S. Department of Homeland Security and allegations in a related indictment by the U.S. Justice Department.[42]

Based on the above observations from individuals well versed on the nation's security, the Attorney General recommends that the Commission require all jurisdictional utility companies to not only comply with the mandatory and voluntary standards, guidelines and resources cited in the majority report, but to exercise the best foreseeable measures possible to secure their companies' cybersecurity.

IX. CAC Comments

Utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks.

[39] Cybersecurity Landscape for the Utility Industry and Considerations for State Regulators, Chairman's Forum on Cybersecurity and Critical Infrastructure, January 25, 2012, Frankfort KY, Patrick Miller, President & CEO, EnergySec, Video timer at 9:20 to 9:47.

[40] Rebecca Scorzato and Eblen Kaplan, *Your Company is Going to Get Hacked. Will It Be Ready?*, Forbes, June 6, 2014.

[41] *See* http://cnsnews.com/news/article/panetta-warns-cyber-pearl-harbor-capability-paralyze-country-there-now.

[42] *See* http://www.cnn.com/2014/05/21/us/hackers-public-utility/, http://www.powermag.com/u-s-charges-chinese-hackers-for-attacks-on-nuclear-and-solar-firms/?hq_e=el&hq_m=2885946&hq_l=9&hq_v=9d93732182; and http://www.justice.gov/opa/pr/2014/May/14-ag-528.html

HOW NATURAL GAS COMPANIES MIGHT PARTICIPATE IN THE ELECTRIC SMART GRID

How Natural Gas Companies Might Participate In the Electric Smart Grid

I. Executive Summary

As the Commission acknowledged in its order opening this proceeding, "Smart Grid and Smart Meter issues are predominantly focused on the electric industry."[43] Though that is true, Kentucky's natural-gas local distribution companies (LDCs) have in some ways pioneered deploying automated and smart technologies among utility operations, having deployed SCADA in their distribution systems and AMR in meter reading for many years. But having already achieved the efficiencies associated with those technologies means that LDCs and their customers may have less to gain from further smart-technology deployments. Also, there are a number of benefits or efficiencies that electric smart technologies might provide or enable that would not benefit LDCs, such as time-of-use or dynamic pricing and remote-reconnection capabilities. Nonetheless, the LDCs among the Joint Utilities remain committed to seeking economical means of participating in the electric smart grid or of developing an independent gas smart grid.

II. Scope of the Natural Gas Participation Section

This section addresses Kentucky's natural-gas LDCs' current deployments of automated and smart technologies, the ways in which the electric smart grid and the gas smart grid differ, and issues related to future involvement of the natural-gas LDCs in the electric smart grid.

III. Natural-Gas LDCs' Current Deployments

A. Atmos Energy

Atmos Energy has approximately 500 wireless meter reading ("WMR") devices in Kentucky. Those devices are all centralized in Livermore, Kentucky, and were installed in 2011. Atmos Energy anticipates installing additional WMR devices in Kentucky over time.

Atmos Energy uses a SCADA system to electronically monitor its distribution system. The SCADA system is located within Atmos Energy's Gas Control department, which monitors the distribution system 24/7. The SCADA system monitors key flow points on the system and the Gas Control department can remotely control valves, pressures, and flows at those locations. The SCADA system cannot remotely control meters at a customer's premise.

B. Columbia Gas

Columbia Gas began utilizing AMR devices on hard-to-reach meters in 2009 as part of its meter-replacement program. The AMR devices that Columbia Gas deploys provide a simple digital reading of the mechanical meter register. Only the customer's meter reading is

[43] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 8 (Oct. 1, 2012).

communicated by the AMR device using radio technology to transmit the meter reading to a specially equipped company vehicle driving through neighborhoods. Columbia Gas is installing AMR devices on all residential and commercial meters in 2014.

Columbia Gas uses a SCADA system to electronically monitor gas flows on its distribution system. The SCADA system is part of the Gas Control department and monitors key flow points on the system. The Gas Control department is staffed 24 hours a day, every day of the year, and can remotely control critical valves, regulators, and flows at certain locations on Columbia Gas's system, but not meters at an individual customer premise.

C. Delta Natural Gas

Delta Gas installed remote meter reading many years ago on 100% of its system. This process utilizes devices installed on each meter that transmit meter reads to use in customer billing. Delta has no current plans to implement smart meters (AMI) or to go beyond the current automated meter reading used with its customers. The current system does not provide hourly or daily data, and does not provide any information back to the customer. Meters are read monthly.

Delta utilizes a SCADA system to monitor gas flows electronically on its system. Delta operates a 24/7 gas control function as a part of its normal operations. This system monitors key flow points on Delta's system and provides for remote-controlled valves, pressure, and flow controls on some of those points. Delta does not control valves remotely or electronically for meters at a customer's premise.

D. Duke Energy

Duke Energy Kentucky uses a SCADA system to electronically monitor and control its gas transmission and distribution systems 24/7. The SCADA system monitors key flow points on the system for flow, pressure, and odorant-injection rates. Gas Control uses SCADA to remotely control, valves, regulators, and pumps. The SCADA system does not monitor or control equipment on a customer's premise.

Combination gas and electric utility companies may have the unique ability to leverage smart-grid back-office systems to provide customers with enhanced data that may not otherwise be cost-effective for a stand-alone natural-gas utility to implement. This shared back-office communication infrastructure across common platforms may provide for additional customer-usage information obtained through automated meter-reading capabilities. For example, gas meters and electric meters could communicate through the same communication-relay point that backhauls data to the company's central processing systems. Sharing common infrastructure could allow combination utilities to more efficiently build out the infrastructure necessary to provide automated-metering services for both gas and electric.

As an example, Duke Energy Ohio's gas and electric customers benefit from a shared communication infrastructure as described above. Today, both gas and electric meter reads travel a common communication path back to the Company's central processing systems. After gas and electric meter reads are confirmed, customers are able to login to their individual customer internet portal page to view their previous daily usage information for both gas and electric.

E. LG&E

As have the other LDCs, LG&E has deployed gas SCADA equipment enabling 24/7 electronic monitoring of more than 9,000 data points at over 260 locations within LG&E's gas system. LG&E's SCADA system enables remote control of equipment at 39 of those locations. The locations monitored or controlled include city-gate stations, gas-regulator stations, compressor stations, underground-gas-storage-field equipment, pipeline valves, and large-volume-customer-metering sites. LG&E does not remotely control equipment at customer-metering sites.

On the customer-facing side of its gas business, LG&E has deployed over 32,000 AMR devices installed on gas meters which are difficult to access. The AMR devices utilize a radio transmitter to transmit meter readings to meter-reading vehicles when the vehicles make their scheduled patrols.

IV. How the Smart Grid Differs for Electric Utilities and Natural-Gas LDCs

There are several important differences between electric and gas utilities and the services they provide that affect how gas utilities might participate in the smart grid.

A. Natural-gas LDCs do not use time-of-use or dynamic-pricing structures

Natural-gas LDCs purchase natural gas days, weeks, or months ahead of the time they supply gas to their customers. Therefore, time-based or other dynamic-pricing regimes do not make sense for LDC customers, reducing the potential economic benefit of providing hourly or real-time pricing and consumption information to customers.

B. Much retail natural-gas use is not truly discretionary or easily adjustable

Retail customers, and particularly residential customers, tend to use natural gas in non-discretionary ways. For example, a typical retail natural-gas customer may have a gas furnace, a gas water heater, and a gas stove and oven. Of those items, only the stove and oven use may be meaningfully discretionary; when temperatures drop, customers must keep their homes warm. Even if a customer desires to reduce gas use somewhat by turning down a thermostat, adjusting a water-heater setting is not something customers are likely to do with any frequency. This is particularly true when natural-gas prices are low.

C. There are not many, if any, smart-grid-related operational savings beyond those the natural-gas LDCs already capture through AMR

For example, safety requirements would prevent natural-gas LDCs from using a remote reconnection feature of smart gas meters (if such meters exist; to the Joint Utilities' knowledge, there are no smart gas meters with remote connection or disconnection capabilities). This limits the additional operational benefits smart meters might provide beyond the meter-reading savings the natural-gas-only LDCs in Kentucky have captured through AMR.

D. Natural-gas-only LDCs cannot benefit from the cost-sharing between electric and gas smart-grid communications as readily as combined electric and gas utilities

For combined electric and gas utilities, the ability to share a single communications network for electric and gas smart components might help make a smart-grid deployment more economical for both kinds of utility service. For example, Duke Energy Ohio uses a single communications network for its electric and gas meters, as well as a combined customer-information portal. But it will be harder for natural-gas-only LDCs to realize the savings of using a combined communications system. The gas-only LDCs among the Joint Utilities serve customers across multiple electric-utility territories; for each LDC to coordinate its smart components' communications systems with multiple electric providers' communications systems would be challenging at best. Therefore, it seems unlikely that LDC smart-grid deployments would benefit from sharing costs with electric utilities, reducing the relative economic attractiveness of such potential deployments.

V. Future Considerations

Although a gas smart grid faces challenges that differ from the electric smart grid, the LDCs among the Joint Utilities believe it is important to stay informed about developments that may change the value proposition a gas smart grid—or an integrated gas and electric smart grid—can offer. There are initiatives in this regard that the LDCs are monitoring or participating in to ensure they are aware of relevant developments. For example, the Gas Technology Institute ("GTI") is working on gas smart-meter and smart-grid areas. (Appendix D to this report is a two-page document from the American Gas Association summarizing some of GTI's work on how the gas and electric smart grids might complement and integrate with each other.) GTI set up a Gas Technology Working Group within the Smart Grid Interoperability Panel ("SGIP"). They plan to investigate the interaction between the gas delivery and electric power delivery systems with respect to interoperability standards, common technological paradigms, and associated system implementations. A major emphasis will be an investigation of the advantages available to both industries with the development of interoperability standards that will foster the integration of gas systems into the electric-centric smart grid.

The LDCs further believe their participation in this case has increased their awareness of what their electric-utility colleagues are doing in the smart-grid arena, which may contribute to future collaboration and cooperation between electric and gas utilities in Kentucky.

HOW NATURAL GAS COMPANIES MIGHT PARTICIPATE IN ELECTRIC SMART GRID

VI. EISA 2007 Smart-Grid Investment and Information Standards

The proposed EISA 2007 Smart-Grid Investment and Information Standards explicitly apply only to electric utilities, and therefore would not apply by their own terms to natural-gas LDCs. That notwithstanding, the Joint Utilities agree that any natural-gas smart-technology deployment should be economical.

VII. Conclusion

Although there are potentially fewer benefits to additional smart-technology deployments and higher hurdles to such deployments for LDCs, Kentucky's LDCs among the Joint Utilities remain committed to seeking economical means to improve information flow to their customers through smart-grid participation.

VIII. AG Comments

The Attorney General has no additional comments with regard to this chapter.

IX. CAC Comments

No comments.

COST RECOVERY

Cost Recovery

I. Executive Summary

For utilities to invest with confidence in smart-grid technologies to improve the service and information their customers receive, they must have reasonable assurance of cost recovery for their prudent investments and for the remaining book costs of the existing equipment or facilities the smart-grid facilities will replace. There is nothing novel about this concept; it is an axiom of regulated-utility investments, whether for smart technologies or otherwise.

But because utilities may and are deploying smart technologies under different circumstances, in different ways, at different paces, and to different extents, there cannot be a one-size-fits-all approach to cost recovery for, or review of, smart-technology deployments. Instead, to encourage the most economically rational yet innovative uses and deployments of smart technologies: (1) all forms of cost recovery should be available for utilities to consider and propose to the Commission, including traditional base rates, existing cost-recovery mechanisms (e.g., demand-side management ("DSM") riders), and new riders or surcharge mechanisms; (2) utilities proposing smart-technology deployments that will necessitate retiring existing utility assets with unrecovered book life should take the cost of those retirements into account in their cost-benefit analyses and be able to recover that cost if the deployment is prudent; and (3) additional smart-grid-specific review proceedings or criteria are unnecessary for smart-grid deployments because existing cost-recovery and other review proceedings and mechanisms are sufficient, including CPCN proceedings and various kinds of rate proceedings. In particular concerning the last point, the Joint Utilities continue to oppose the imposition of the EISA 2007 Smart-Grid Investment Standard or any derivative thereof due to the sufficiency of existing review mechanisms and criteria.

II. Scope of the Cost Recovery Section

This section addresses the appropriate means of cost recovery for smart-technology investments, including the unrecovered cost of obsolete technologies replaced by smart technologies. This section addresses also the sufficiency of existing review mechanisms and criteria for evaluating the prudence of smart-technology investments.

III. Utilities' Past and Current Cost-Recovery Approaches for Smart-Technology Investments

A. AEP

The recovery of Smart Grid investments such as AMI meters and Distribution Automation – Circuit Reconfiguration (DA-CR) is similar to other types of distribution investments, which require a return on and of capital investments and recovery of operations and maintenance expenses. Several of the AEP state jurisdictions, including Ohio, Kentucky, Michigan, Indiana, Tennessee, Virginia, and West Virginia, have deployed AMR meters, which are not considered to be smart-grid technology. In addition, AMI meters are installed in parts of Ohio, Oklahoma, Texas, and a small concentration in Indiana. AEP's cost-recovery methods for its smart-grid investments are base rates in Oklahoma (see Cause No. PUD 200800144), a rider mechanism in Ohio (see Case Nos. 08-917-EL-SSO, 08-918-EL-SSO, 11-346-EL-SSO and 11-348-EL-SSO), and a customer surcharge in Texas (see Docket No. 36928). Future smart-grid investments in Indiana would be recoverable through base rates or a rider mechanism.

Cost recovery of Energy Efficiency/Demand Response ("EE/DR") programs, including Volt/VAR Optimization (VVO), is similar to smart-grid programs, except that almost exclusively these costs are recovered through riders or trackers. EE/DR riders are utilized in all of AEP's operating companies that offer EE/DR programs to recover program costs, net lost revenues, and shared savings. Traditional EE/DR programs are expensed, meaning no capital costs are involved. VVO is different in that it provides EE/DR savings, but is predominately a capital expense. Both the Michigan Public Service Commission and the Indiana Utility Regulatory Commission have approved plans for Indiana Michigan Power ("I&M") to qualify VVO as an energy-efficiency program. In Indiana, carrying cost and depreciation for VVO are recoverable through the existing EE/DR rider (see Cause No. 43827 DSM 3). In Michigan, I&M has authority to defer costs associated with VVO for recovery in the next base-rate case (see Case No. U-17353).

B. Atmos Energy

As part of a stipulation in a 2010 Colorado rate case, Atmos Energy was allowed to file for expedited approval of a pilot program in a separate docket to charge a surcharge for the installation of approximately 35,000 AMI devices in Greeley, Colorado. The surcharge was charged to both residential and commercial customers state-wide. The pilot program expanded over subsequent years to include Atmos Energy's entire Colorado system of 112,000 residential and commercial meters. The surcharge is no longer in effect because the program has been completed.

C. Columbia Gas

As part of a general rate case in 2013, Columbia Gas received approval to install AMR devices throughout its 30-county service area in 2014, and was granted cost recovery in the forward-looking test year utilized in its filing.[44]

D. Cooperatives

Three distribution cooperatives have sought regulatory treatment concerning the write-off of the cost of meters that were being retired and the associated accumulated depreciation in conjunction with the deployment of AMI.

1. Taylor County RECC. In September 2008, Taylor County filed Case No. 2008-00376, an application with the Commission requesting approval of a deferral plan for retiring meters. Taylor County had been granted a CPCN

[44] *See In the Matter of: Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates for Gas Service*, Case No. 2013-00167, Order (Dec. 13, 2013).

in Case No. 2006-00286 to install solid state AMI meters which would replace mechanical meters. As a result of the installation, Taylor County determined it would experience a $1.2 million extraordinary property loss. Taylor County sought approval from the U.S. Department of Agriculture's Rural Utilities Service ("RUS") to defer the extraordinary property loss and proposed to amortize the resulting regulatory asset over a period of five years. RUS informed Taylor County that Commission authorization for the deferral must be granted before it would approve the proposed plan. In its December 2008 Order in Case No. 2008-00376, the Commission approved Taylor County's request to establish a regulatory asset and amortize that asset over five years for accounting purposes only.

In August 2012 Taylor County filed Case No. 2012-00023 an application to adjust its rates. In its March 2013 Order, the Commission agreed with Taylor County that the appropriate service life for the AMI system was 15 years. Noting that the previously established retired meter regulatory asset would be fully amortized by April 2014, the Commission extended the amortization period three years from the date of the March 2013 Order. The Commission stated this approach was consistent with its practice in rate proceedings involving amounts that remain to be fully amortized.

2. Shelby Energy Cooperative. In March 2012, Shelby Energy filed Case No. 2012-00102, an application with the Commission requesting approval to establish a regulatory asset for the write-off of retired mechanical meters and the associated accumulated depreciation. Shelby Energy had been granted a CPCN in Case No. 2010-00244 to install an AMI system which would replace mechanical meters. As a result of the installation, Shelby Energy determined it would experience a loss of approximately $444,000. Shelby Energy sought approval from the RUS and the Commission to defer the loss and proposed to amortize the resulting regulatory asset over a period of five years. The RUS gave its approval to implement Shelby Energy's proposed plan, but noted that the Commission must authorize the deferral and subsequent recovery of costs. In its April 2012 Order in Case No. 2012-00102, the Commission approved Shelby Energy's request to establish a regulatory asset and amortize that asset over five years for accounting purposes only. The Commission noted that the recovery of the amortization in rates would be considered if raised by Shelby Energy in its next rate case.

3. South Kentucky RECC. In June 2011, South Kentucky filed Case No. 2011-00096, an application to adjust its rates. In its application, South Kentucky sought approval of a 15-year service life for its AMI system and annual depreciation expense on the full cost of the investment in the AMI system. The Commission had granted South Kentucky a CPCN for the AMI system in January 2010 in Case No. 2009-00489. In its March 2012

COST RECOVERY

Order in Case No. 2011-00096 the Commission agreed with the use of a 15-year service life for the AMI system. The Commission reduced the allowed annual depreciation expense to recognize that approximately 49 percent of the investment had been funded through a U. S. Department of Energy grant.

Also in its 2011 rate application, South Kentucky determined it would realize a loss of approximately $3.7 million on the early disposition of its existing mechanical meters. South Kentucky requested that this loss be recognized as a regulatory asset and allow for rate-making purposes the amortization of the loss over a five-year period. In its March 2012 Order the Commission found the special accounting treatment to be reasonable, but determined an amortization period of 15 years was appropriate instead of the proposed five-year period. Citing RUS accounting requirements, the Commission stated that South Kentucky's depreciation rates were determined utilizing the whole life method and under that method, losses would not have been charged against revenue unless an accounting treatment alternative to that prescribed by the RUS was allowed. South Kentucky had sought an alternative treatment when it requested regulatory asset treatment, which the Commission approved. The Commission concluded that the use of the whole life method should not impact the amortization period. The Commission further observed that had the remaining life method been utilized to calculate depreciation rates, the loss on the mechanical meters would have been recognized for accounting and rate-making purposes over the 15-year life of the AMI project. Consequently, the Commission required the regulatory asset to be amortized over 15 years.

South Kentucky sought rehearing on the annual depreciation expense and regulatory asset amortization decisions. In its May 2012 rehearing Order, the Commission confirmed its original decisions. The Commission also noted the five-year amortization periods authorized for Taylor County and Shelby Energy were approved for accounting purposes only and had no impact on the rates charged by either utility and paid for by their respective customers.

E. Delta Natural Gas

Delta Gas installed remote meter reading starting in 1996. Devices were installed on meters to transmit meter readings for customer billing. Delta installed these gradually over a period of years, completing 100% of its meters in 2003. As investments were made in adding these meter reading devices to automate Delta's meter reading, the investments were recorded as assets of Delta and then were included in subsequent general rate cases as rate base investment.

COST RECOVERY

F. Duke Energy

Duke Energy has received special cost recovery treatment for grid modernization investments in some of the jurisdictions in which it operates. As an example, Duke Energy Ohio was granted annual rider recovery for its smart grid investment program in Ohio. These investments included a full deployment of AMI and various distribution-automation ("DA") oriented investments. Duke Energy Ohio files annually with the Public Utilities Commission of Ohio reports detailing the program implementation progress along with associated costs. Duke Energy Ohio also received approval to include in base rates accelerated depreciation of equipment rendered obsolete due to the smart grid program.

G. LG&E and KU

In Case No. 2007-00117, LG&E applied for, and the Commission approved, DSM cost recovery of the non-customer-specific costs of LG&E's three-year responsive-pricing and smart-metering pilot program. The program involved deploying over 1,400 smart meters to residential and small commercial customers, as well as other forms of technology designed to enable customers to understand and better control their energy usage. LG&E recovered about $2 million through its DSM mechanism for the pilot program.

LG&E and KU recently proposed in their current DSM case, Case No. 2014-00003, to recover the cost of deploying up to 10,000 total advanced meters across the LG&E and KU service territories, as well as related support and communications technologies. All told, LG&E and KU propose to recover a total of about $5.7 million in capital and operating and maintenance costs for the Advanced Metering Systems offering for the years 2015 through 2018.

IV. Cost-Recovery Considerations for Smart Technology

There are several valid rate options for utilities to consider for cost recovery of possible smart-technology deployments. All options should be available for utilities to consider and propose to the Commission to remove possible obstacles to economical and innovative smart-technology deployments.

A. Base rates

Particularly for investments that do not involve large or rapid capital outlays, base rates (set using an historical test year) are an option for utilities to consider for recovering the costs of smart-technology deployments. Such cases provide an opportunity for thorough, deep review of the prudence of such investments. Using forecasted test years is also an option, particularly for utilities considering larger or more rapid capital outlays.

B. Existing cost-recovery mechanisms

Some smart-technology deployments may be natural candidates for cost recovery through existing riders or surcharge mechanisms. For example, smart-meter deployments may be ideal for DSM cost recovery due the explicit statutory directive in KRS 278.285(1)(h) for the

Commission to consider in a utility's DSM plan "[n]ext-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home." Other future smart technologies may have environmental benefits that would qualify them for cost recovery through utilities' environmental-surcharge mechanisms. Using established cost-recovery mechanisms has the benefit of thorough prudence review proceedings and well-established procedures for cost recovery.

C. New rider mechanisms

Cost recovery though new riders or surcharge mechanisms may be appropriate for some smart-technology deployments, such as those that require relatively high or unpredictable capital investments. The Commission has clear authority to approve such mechanisms when it determines they are appropriate.[45] Rider mechanisms, whether existing or new, have the advantages of increasing transparency and ensuring accurate cost recovery through periodic true-up and review proceedings. Also, riders tend to decrease the relative cost of debt capital by better ensuring capital recovery.

D. Recovering investments in facilities replaced by smart components

In addition to preserving rate options for recovering the costs of smart-technology investments, it is crucial for the Commission to permit utilities to recover the remaining book value of the obsolete equipment or facilities the smart technologies replace. Requiring utilities simply to absorb those unrecovered costs—turning them into genuinely stranded cost—would necessarily slow the deployment of smart technology in Kentucky, and likely to customers' detriment. The better approach is for utilities to take into account the unrecovered cost of obsolete equipment when performing cost-benefit analyses to evaluate possible smart-technology deployments. This will ensure economical deployments, both protecting utilities' financial health and delivering benefits to customers. The Commission has recognized the need to provide means for utilities to recover the remaining book value of obsolete equipment in new-meter-deployment cases by approving regulatory assets for the unrecovered costs of replaced equipment and amortizing the assets over reasonable terms of years.[46] The Joint Utilities agree with this approach, which protects customers from rate shock through gradualism while ensuring utilities have full cost recovery.

[45] *Kentucky Public Service Commission v. Commonwealth of Kentucky ex rel. Conway*, 324 SW 3d 373, 374 (Ky. 2010) ("We hold that so long as the rates established by the utility were fair, just, and reasonable, the PSC has broad ratemaking power to allow recovery of such costs outside the parameters of a general rate case and even in the absence of a statute specifically authorizing recovery of such costs.").

[46] *See In the Matter of: Request of Shelby Energy Cooperative for Approval to Establish a Regulatory Asset in the Amount of $443,562.75 and Amortize the Amount Over a Period af Five (5) Years*, Case No. 2012-00102, Order (Apr. 16, 2012) (approving requested regulatory asset for remaining book value of meters being replaced with AMI meters, and approving five-year amortization of regulatory asset); *In the Matter of: Filing of Taylor County Rural Electric Cooperative Corporation Requesting Approval of Deferred Plan for Retiring Meters*, Case No. 2008-00376, Order (Dec. 9, 2008) (approving requested regulatory asset for remaining book value of meters being replaced with AMR meters, and approving five-year amortization of regulatory asset).

E. CPCN proceedings are not necessary for all smart-technology deployments

Finally, although CPCN proceedings may be necessary for certain new and large smart-technology deployments, the Commission should not require such proceedings for all smart-technology deployments. Many smart-technology deployments are merely replacements or upgrades of existing utility equipment, not new construction requiring a CPCN. Some utilities may choose to seek CPCNs for smart-technology proposals to obtain some assurance of future cost recovery (particularly when utilities intend to seek base-rate recovery) even when CPCNs would not be strictly necessary; this option should remain available to utilities. But creating a blanket rule requiring all utilities to seek CPCNs for any smart-technology deployments might impermissibly conflict with KRS 278.020 and would likely slow the deployment of smart technologies in Kentucky by erecting unnecessary cost and time barriers to their deployment.

V. EISA 2007 Smart-Grid Investment and Information Standards

The Joint Utilities continue to oppose adopting the EISA 2007 Smart Grid Investment Standard on numerous grounds articulated throughout this Report. With respect solely to cost recovery, the Joint Utilities oppose the standard because it would potentially limit cost-recovery options, which in turn could slow or eliminate otherwise economical smart-technology deployments in Kentucky.

Similarly, the Joint Utilities continue to oppose the EISA 2007 Smart Grid Information Standard on numerous grounds. With respect to cost recovery, the Joint Utilities oppose the standard because it could create an obligation to deploy smart technologies, and particularly smart meters, without regard for whether such deployments would be economical or whether utilities making such deployments would have assurance of full cost recovery not just of the deployments themselves but also the unrecovered costs of any replaced equipment.

VI. Conclusion

A key to ensuring that Kentucky's utilities deploy smart technologies beneficially is the assurance of full and timely recovery of the prudent costs of such deployments, as well as the unrecovered costs of replaced equipment. Having a wide variety of cost-recovery options will help address the unique circumstances of each utility and each potential deployment, in turn reducing barriers to economical and innovative smart-technology deployments in Kentucky.

VII. AG Comments

The Attorney General does not oppose the economical and cost-effective investment and use of smart technologies, but reserves his position subject to a case-by-case review of cost recovery mechanisms. The Attorney General has no additional comments with regard to this chapter.

VIII. CAC Comments

No comments.

EISA 2007 SMART GRID INFORMATION AND INVESTMENT STANDARDS

EISA 2007 Smart Grid Information and Investment Standards

I. Executive Summary

The Joint Utilities continue to believe that smart technologies, both customer-facing and grid-deployed, hold much promise; indeed, as detailed at various points in this report, all of the utility members of the Joint Utilities have deployed advanced or smart technologies in different ways and degrees. But not all technologies are sensible to deploy in all circumstances, and each utility must have the flexibility to propose solutions that are prudent for their customers. These solutions will vary depending on geography, customer density, existing system constraints and resources, and a host of other factors. Also, smart technologies continue to advance and mature at a rapid pace, and there is no industry consensus about which technologies every utility must deploy. Moreover, none of the jurisdictions in which the Joint Utilities' utility affiliates operate has adopted either of the EISA 2007 Smart Grid Standards. Therefore, the Joint Utilities continue to hold the position they expressed collectively in their May 20, 2013 Joint Comments in this proceeding, namely that each utility's unique circumstances and the pace of technological change make it unnecessary, and likely counterproductive, to impose uniform, one-size-fits-all standards, such as the EISA 2007 Smart Grid Information and Investment Standards. The better approach is to use the Commission's existing authority to ensure the prudence of utility proposals and deployments concerning smart technologies, as the Commission currently does concerning all utility operations and investments.

II. The Joint Utilities Unanimously Agree the Commission Should Not Adopt the EISA 2007 Smart Grid Information Standard

The Joint Utilities continue to oppose unanimously any adoption of the EISA 2007 Smart Grid Information Standard because it could require utilities to make uneconomical investments. The standard would require utilities to provide customers direct access to a wide array of data without regard for the costs or benefits of providing the data:

- Prices: Purchasers and other interested persons shall be provided with information on time-based electricity prices in the wholesale electricity market, and time-based electricity retail prices or rates that are available to the consumers.

- Usage: Purchasers shall be provided with the number of electricity units, expressed in kWh, purchased by them.

- Intervals and Projections: Updates of information on prices and usage shall be offered on a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

EISA 2007 SMART GRID INFORMATION AND INVESTMENT STANDARDS

> - Sources: Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent that it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.
>
> - Customer data: Customers shall be able to access their own information at any time through the internet and by other means of communication elected by the electric utility for smart grid applications. Other interested persons shall be able to access information not specific to any customer through the Internet. Customer-specific information shall be provided solely to that customer.[47]

The current offering of residential time-based or time-of-use pricing options is limited to voluntary programs, and such pricing options have not yet been widely adopted in Kentucky. Therefore, there is no need to require utilities to provide the extensive pricing, interval, and projection information the EISA 2007 Smart Grid Information Standard requires. Moreover, the EISA 2007 Smart Grid Information Standard takes no account of the economics of serving the different customers and service territories in Kentucky; rather, it would impose a one-size-fits-all requirement that all utilities provide their customers the same kinds of information in presumably similar, if not identical, ways. Such a standard could require utilities to make currently uneconomical investments in customer-facing information technology.

Instead, the Commission should continue to use its existing review processes and authority to ensure utilities are providing customers the information they need in economical ways. That will allow the Commission's review of information provision to customers to recognize each utility's unique characteristics, including the unique costs and benefits of providing certain kinds of information in certain ways to each utility's customers.

III. The Joint Utilities Unanimously Agree the Commission Should Not Adopt the EISA 2007 Smart Grid Investment Standard

The Joint Utilities continue to oppose unanimously any adoption of the EISA 2007 Smart Grid Investment Standard because it would be largely redundant while potentially stifling useful innovation in smart-technology proposals, including potential cost-recovery methods. The standard would require as follows:

> Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of

[47] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 5 (Oct. 1, 2012).

> the State demonstrate to the State that the electric utility considered an investment in a qualified Smart Grid system based on appropriate factors, including:
>
> - total costs;
> - cost-effectiveness;
> - improved reliability;
> - security;
> - system performance; and
> - societal benefit.
>
> The EISA 2007 Smart Grid Investment Standard also requires each state to consider rate recovery of Smart Grid capital expenditures, operating expenses, and other costs related to the deployment of smart grid technology, including a reasonable return on the capital expenditures. As part of the rate recovery consideration, each state is to also consider recovery of the remaining book-value of obsolete equipment associated with smart grid deployment.[48]

Because the Commission already has the ability and duty to review the costs and benefits of utility proposals, the proposed standard is unnecessary; moreover, intervention by advocates such as the AG already helps ensure the thorough review of utility proposals. In addition to being largely redundant, the proposed standard may inhibit useful innovation to the extent it introduces constraints on what can be considered when utilities make smart-grid-related proposals, including constraints on costs and benefits to consider, as well as cost-recovery methods. Therefore, the Commission should decline to adopt the EISA 2007 Smart Grid Investment Standard in favor of continuing to use its existing authority to review utility proposals to ensure they are cost-effective and that each utility's means of cost recovery is appropriate on a case-by-case basis.

IV. Conclusion

The Joint Utilities do not oppose the economical use of smart technologies. But the Joint Utilities do oppose mandatory standards that could require uneconomical investments, stifle innovation, or otherwise curtail each utility's ability to implement what is most economical and sensible for its customers and service territory. Moreover, it is noteworthy that none of the jurisdictions in which the Joint Utilities' utility affiliates operate have adopted either of the EISA 2007 Smart Grid Standards. The Joint Utilities therefore oppose the EISA 2007 Smart Grid Information and Investment Standards, and the Commission should not adopt them.

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[48] *Id.* at 4.

EISA 2007 SMART GRID INFORMATION AND INVESTMENT STANDARDS

V. AG Comments

The Attorney General does not oppose the economical use of smart technologies consistent with the other comments expressed by the Attorney General in this report. Consistent with the reasons stated in this chapter, the Attorney General concurs with the unanimous agreement of the Joint Utilities that the Commission should not adopt EISA 2007 Smart Grid Information and Investment Standards.

VI. CAC Comments

No comments.

CONCLUSION AND RECOMMENDATIONS

Conclusion and Recommendations

The analytical tools and frameworks provided in this report are the culmination of over five and a half years of examination of smart-grid related issues by the Joint Utilities. These tools and frameworks, operating as voluntary guidelines, may assist utilities when considering smart-technology investments and deployments. But it remains the well- and long-examined view of all of the Joint Utilities that the Commission should not impose any mandatory, uniform guideline or rule for utilities' use of smart technologies. Instead, the Commission should continue to rely on time-tested and proven review processes to review the prudence of utility smart-technology investments and deployments. The Joint Utilities therefore unanimously recommend that the Commission issue a final order closing this case without further proceedings and declining to impose the EISA 2007 Smart Grid Information Standard, the EISA 2007 Smart Grid Investment Standard, or any other smart-technology-related standard.

APPENDIX A: ABBREVIATIONS AND ACRONYMS

Appendix A: Abbreviations and Acronyms

AEP	American Electric Power
AG	Attorney General of the Commonwealth of Kentucky by and through His Office of Rate Intervention
AGA	American Gas Association
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
C2M2	U.S. Department of Energy's Electricity Subsector Cybersecurity Capability Maturity Model
CAC	Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc.
CIP	Critical Infrastructure Protection
Commission	Kentucky Public Service Commission
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical-Peak Pricing
CRN	Cooperative Research Network
DA	Distribution Automation
DA-CR	Distribution Automation – Circuit Reconfiguration
DSM	Demand-Side Management
DTN	LG&E Downtown Secondary Network
EE/DR	Energy Efficiency/Demand Response
EISA 2007	Energy Independence and Security Act of 2007
ESPI	Energy Service Provider Interface
FERC	Federal Energy Regulatory Commission
FTC	Federal Trade Commission

APPENDIX A: ABBREVIATIONS AND ACRONYMS

GTI	Gas Technology Institute
I&M	Indiana-Michigan Power
Joint Utilities	Atmos Energy Corporation, Big Rivers Electric Corporation, Big Sandy Rural Electric Cooperative Corporation, Blue Grass Energy Cooperative Corporation, Clark Energy Cooperative, Inc., Columbia Gas of Kentucky, Inc., Cumberland Valley Electric, Delta Natural Gas Company, Inc., Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Farmers Rural Electric Cooperative Corporation, Fleming-Mason Energy Cooperative, Inter-County Energy Cooperative Corporation, Jackson Energy Cooperative Corporation, Jackson Purchase Energy Corporation, Kenergy Corp., Kentucky Power Company, Kentucky Utilities Company, Licking Valley Rural Electric Cooperative Corporation, Louisville Gas and Electric Company, Meade County Rural Electric Cooperative Corporation, Nolin Rural Electric Cooperative Corporation, Owen Electric Cooperative, Inc., Salt River Electric Cooperative Corporation, Shelby Energy Cooperative, Inc., South Kentucky Rural Electric Cooperative Corporation, and Taylor County Rural Electric Cooperative Corporation
kWh	Kilowatt-hour
KU	Kentucky Utilities Company
LDC	Local Distribution Company
LG&E	Louisville Gas and Electric Company
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NISTIR	National Institute of Standards and Technology Interagency Report
NRECA	National Rural Electric Cooperatives Association
OMS	Outage Management System
PSA	Public Service Announcement
PTR	Peak-Time Rebate
RECC	Rural Electric Cooperative Corporation

APPENDIX A: ABBREVIATIONS AND ACRONYMS

RF	Radio Frequency
RTO	Regional Transmission Organization
RTP	Real-Time Pricing
RUS	U.S. Department of Agriculture's Rural Utilities Service
SANS 20	SANS Institute's Top 20 Critical Security Controls
SCADA	Supervisory Control and Data Acquisition
SERC	SERC Reliability Corporation
SGIP	Smart Grid Interoperability Panel
TOD	Time of Day
TOU	Time of Use
TWACS	Two-Way Automatic Communications System
VCC	Voluntary Code of Conduct
VVO	Volt/VAR Optimization

APPENDIX B: RESIDENTIAL DYNAMIC PRICING RATES CURRENTLY AVAILABLE IN KENTUCKY

Appendix B: Residential Dynamic Pricing Rates Currently Available in Kentucky

AEP Kentucky Power Company

None; not applicable.

Big Rivers Electric Corporation's Members

None; not applicable.

East Kentucky Power Cooperative, Inc.'s Members

Big Sandy RECC
Off Peak Marketing Rate – Included with Schedule A-1 Farm & Home (Electric Thermal Storage ("ETS"))

Blue Grass Energy
GS-3 (Residential and Farm Time-of-Day Rate)

Clark Energy
Schedule D: Time of Use Marketing Service (ETS)

Cumberland Valley Electric
Marketing Rate – Attached to Schedule 1 – Rate for Residential, Schools and Churches (ETS)

Farmers RECC
Schedule RM – Residential Off-Peak Marketing – ETS

Fleming-Mason Energy
Schedule RSP-ETS, Residential and Small Power – ETS
Schedule RSP- Time of Day, Residential and Small Power

Inter-County Energy
Schedule 1-A Farm and Home Marketing Rate (ETS)

Jackson Energy
Schedule 11 – Residential Service – Off Peak Retail Marketing Rate (ETS)

APPENDIX B: RESIDENTIAL DYNAMIC PRICING RATES CURRENTLY AVAILABLE IN KENTUCKY

Owen Electric

Schedule I-A Farm and Home – Off-Peak Marketing Rate (ETS)
Schedule 1-B1 – Farm & Home – Time of Day
Schedule 1-B2 – Farm & Home – Time of Day
Schedule 1-B3 – Farm & Home – Time of Day
Schedule 1-B4 – Smart Home Pilot – Time of Day

Salt River Electric

Schedule A-5-TOD Farm and Home Service (Time of Day)
Schedule A-5T-TOD Farm and Home Service Taxable (Time of Day)

Shelby Energy

Off-Peak Retail Marketing Rate (ETS)

South Kentucky RECC

Marketing Rate – Attached to Schedule A Residential, Farm and Non-Farm Service (ETS)

Taylor County RECC

Schedule R-1 Residential Marketing Rate (ETS)

Kentucky Utilities Company and Louisville Gas and Electric Company

Kentucky Utilities Company

Sheet No. 79 – Pilot Program – Low Emission Vehicle Service (LEV)

Louisville Gas and Electric Company

Sheet No. 79 – Pilot Program – Low Emission Vehicle Service (LEV)

APPENDIX C: JOINT UTILITIES' RESIDENTIAL DYNAMIC-PRICING RATES IN OTHER JURISDICTIONS

Appendix C: Joint Utilities' Residential Dynamic-Pricing Rates in other Jurisdictions

AEP[49]

Ohio Power Company - Columbus Southem Power Rate Zone[50]
- Experimental Critical Peak Pricing Service (CPP)
- Experimental Residential Real-Time Pricing Service (RTP)

Public Service Company of Oklahoma
- Variable Peak Pricing Residential Service (VPPRS)[51]

Duke Energy

Duke Energy Carolinas – North Carolina
- Schedule RT (NC) – Residential Service – Time of Use
- Schedule RST (NC) – Residential Service – Time of Use Pilot
- Schedule RET (NC) – Residential Service – All-Electric, Time of Use Pilot

Duke Energy Carolinas – South Carolina
- Schedule RT (SC) – Residential Service – Time-of-Use

Duke Energy Ohio
- Sheet No. 33 – Residential Service – Rate TD, Optional Time-of-Day Rate

Duke Energy Progress – North Carolina
- Schedule R-TOUD 27 – Residential Service – Time-of-Use
- Schedule R-TOU-27 – Residential Service – Time-of-Use

Duke Energy Progress – South Carolina
- Schedule R-TOUD-25 – Residential Service – Time-of-Use
- Schedule R-TOUE-25 – Residential Service - All-Energy Time-of-Use

[49] AEP does not consider TOD rates to be dynamic pricing.
[50] https://www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2014-04-17_AEP_Ohio_Standard_Tariff.pdf.
[51] https://www.psoklahoma.com/global/utilities/lib/docs/ratesandtariffs/Oklahoma/RPSSchedules_01-27-2012.pdf.

APPENDIX D: AMERICAN GAS ASSOCIATION: NATURAL GAS IN A SMART ENERGY FUTURE

Appendix D: American Gas Association: Natural Gas in a Smart Energy Future

AGA American Gas Association

NATURAL GAS IN A SMART ENERGY FUTURE

Natural gas is a foundation fuel for a smart, clean, safe and reliable energy system. It serves as an efficient source of comfort in homes and productivity for businesses. Natural gas has also become a vital fuel source for electric generation – serving peak demand and also balancing the integration of renewable energy.

SOLUTIONS FOR A SMART ENERGY FUTURE

(1) Investments in energy infrastructure will be optimized by looking at all energy options.

Integrating natural gas and electricity as we develop the smart energy grid will lead to cost savings for consumers. The development of a **coordinated network** of sensors and control technologies will help system operators utilize energy resources more **effectively and efficiently,** while also enhancing the safety and reliability of energy delivery.

CASE IN POINT: Natural gas fueled microgrids, interconnected distributed generation and combined heat and power units, are just one example of a smart energy application fueled by clean natural gas. These efficient, independent and lower-cost systems are ideal for those who need both electricity and heat, such as industrial facilities, hospital complexes and college campuses.

(2) A smart energy future will effectively use all available technologies and applications.

Incorporating natural gas applications into the smart energy grid will not only improve **efficiency and flexibility** to meet evolving energy demands, but will also provide solutions to address immediate energy challenges. Employing both new and proven natural gas-based applications – like combined heat and power technologies – provides **immediate solutions** that address increasing electricity demands while decreasing the need to build more large-scale electric generating capacity and transmission lines.

(3) New technology will provide customers with more information about their energy consumption and full range of energy options

Implementing smart technology to help consumers make well informed energy choices is vital to a smart energy future. Consumers need **tools** to understand how they use and manage energy, **pricing options** that allow them to value their energy choices and a selection of **end-use appliances** that best meet their needs. In the smart energy future, consumers will have a clearer picture of their energy usage and will be better able to monitor, manage and conserve energy.

TIME TO ACT: LONG TERM SUCCESSES REQUIRE NEAR TERM POLICY ACTIONS

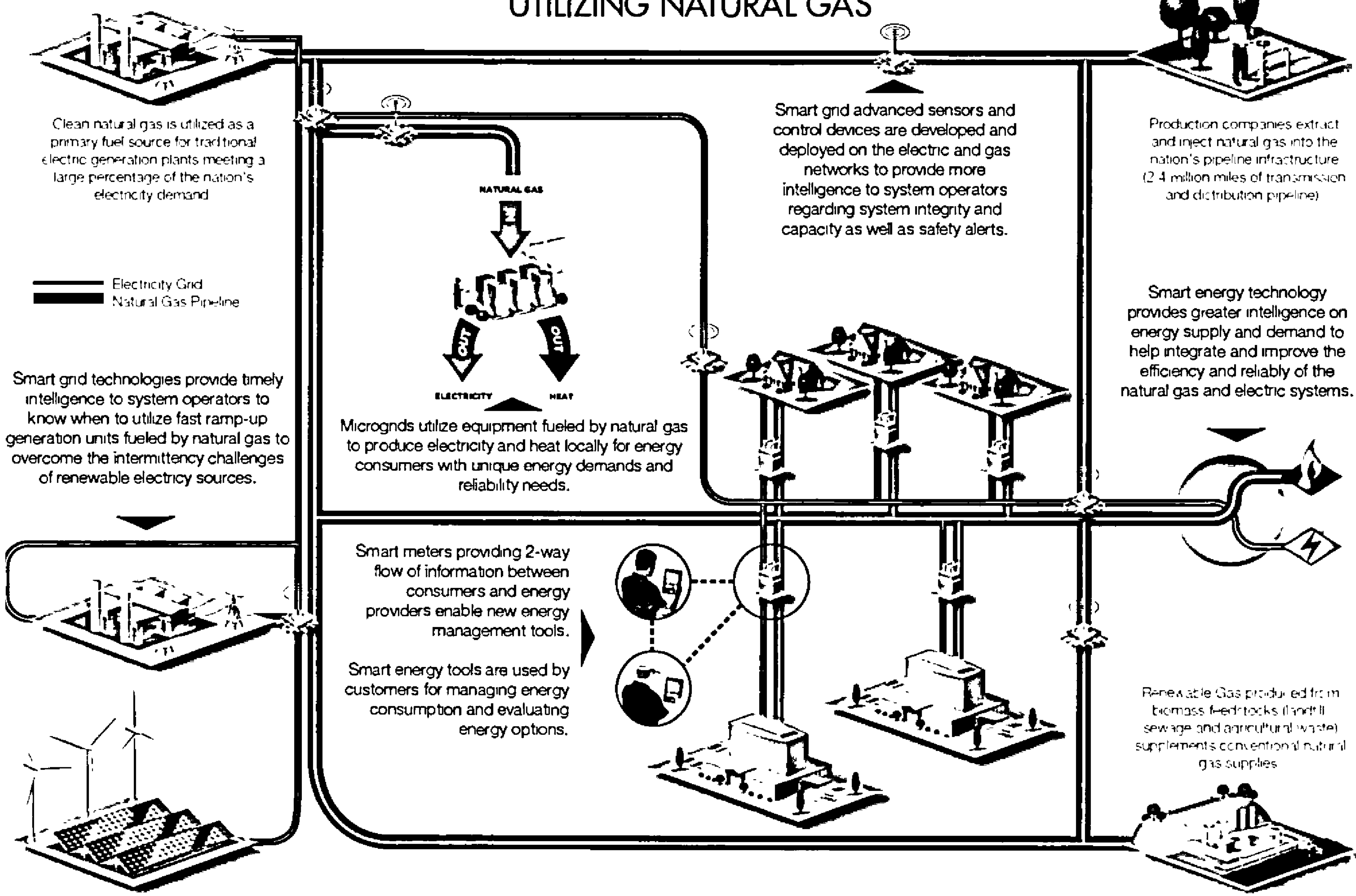
As federal and state policy makers advance a smart energy future, natural gas and natural gas technologies must play a central role.

- Ensure that smart grid implementation policies encourage the integration of natural gas and distributed energy applications.
- Include natural gas in advanced metering infrastructure development.
- Increase governmental funding for expanded research in natural gas safety, reliability and smart energy infrastructure technology.

✓ Smart tools like in-home display units for managing energy use – by illustrating the source energy and emissions impact of energy use measured from the point of generation to the end-use – provide consumers with more complete information about the impact of their energy use decisions on their pocketbooks as well as the environment.

In 2011, GTI and Navigant Consulting released a study outlining the vision of a smart energy future for natural gas The report underscores how effectively utilizing North America's abundant natural gas resource base and infrastructure will lead to increased efficiencies in the residential and commercial sectors and an optimized smart grid Natural gas's role in a smart energy grid will maximize investments designed to strengthen the backbone of the electricity network while enhancing the safety and reliability of an already efficient natural gas system http //media godashboard com/gti/Natural_Gas_in_a_Smart_Energy_Future_01-26-2011 pdf

A SMARTER ENERGY FUTURE
UTILIZING NATURAL GAS



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