COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR FULL DEPLOYMENT OF ADVANCED METERING SYSTEMS	)	CASE NO. 2018-00005

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recording of the evidentiary hearing conducted on July 24, 2018 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the evidentiary hearing conducted on July 24, 2018 in this proceeding;

- A written log listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recording of the evidentiary hearing conducted on July 24, 2018.

A copy of this Notice, the certification of the digital video record, hearing log, and exhibits have been electronically served upon all persons listed at the end of this Notice. Parties desiring to view the digital video recording of the hearing may do so at https://psc.ky.gov/av_broadcast/2018-00005/2018-00005_24Jul18_Inter.asx.

Parties wishing an annotated digital video recording may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

Done at Frankfort, Kentucky, this 1st day of August 2018.

Gwen R. Pinson

Gwen R. Pinson
Executive Director
Public Service Commission of Kentucky

Honorable Allyson K Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

Honorable Iris G Skidmore
415 W. Main Street
Suite 2
Frankfort, KENTUCKY 40601

Duncan W Crosby
Stoll, Keenon, Ogden PLLC
2000 PNC Plaza, 500 West Jefferson St
,   40202-2828

Eileen Ordover
Legal Aid Society
416 West Muhammad Ali Boulevard
Suite 300
Louisville, KENTUCKY 40202

Thomas J FitzGerald
Counsel & Director
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KENTUCKY 40602

Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

Justin M. McNeil
Office of the Attorney General
Office of Rate Intervention
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

Honorable Kurt J Boehm
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

Honorable Kendrick R Riggs
Attorney at Law
Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
Louisville, KENTUCKY 40202-2828

Kent Chandler
Assistant Attorney General
Office of the Attorney General
Office of Rate Intervention
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

Larry Cook
Assistant Attorney General
Office of the Attorney General
Office of Rate Intervention
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

Honorable Lisa Kilkelly
Attorney at Law
Legal Aid Society
416 West Muhammad Ali Boulevard
Suite 300
Louisville, KENTUCKY 40202

Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

Rebecca W Goodman
Assistant Attorney General
Office of the Attorney General
Office of Rate Intervention
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

Rick E Lovekamp
Manager - Regulatory Affairs
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

Robert Conroy
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

Kentucky Utilities Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

Louisville Gas and Electric Company
220 W. Main Street
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Louisville, KY 40232-2010

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CERTIFICATION

I, Angela Fields, hereby certify that:

1. The attached DVD contains a digital recording of the Hearing conducted in the above-styled proceeding on July 24, 2018. Hearing Log, Exhibit List and Witness List are included with the recording on July 24, 2018.

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the Hearing of July 24, 2018.

4. The Hearing Log attached to this Certificate accurately and correctly states the events that occurred at the Hearing of July 24, 2018 and the time at which each ccurred.

Signed this 26th day of July, 2018.

Angela Fields

Angela Fields, Paralegal Consultant

Stephanie Schweighardt

Stephanie Schweighardt, Notary Public
State at Large
Commission Expires: January 14, 2019
ID#: 525987

Judge: Bob Cicero; Talina Mathews; Michael Schmitt

Witness: Paul Alvarez; Michael Ashabraner; Cathy Hinko; David Huff; Rick Lovekamp; John Malloy; Malcolm Ratchford

Clerk: Angela Fields

Date:	**Type:**	**Location:**	**Department:**
7/24/2018	Public Hearing\Public Comments	Hearing Room 1	Hearing Room 1 (HR 1)

Event Time	**Log Event**	
8:19:52 AM	Session Started	
8:19:55 AM	Session Paused	
9:01:02 AM	Session Resumed	
9:01:09 AM	Chairman Schmitt	
	Note: Fields, Angela	Preliminary Comments.
9:01:43 AM	Intro of Counsel	
9:01:44 AM	Camera Lock Deactivated	
9:03:31 AM	Chairman Schmitt	
	Note: Fields, Angela	Notice given. Public Comments?
9:04:02 AM	Ron Bridges	
	Note: Fields, Angela	Public comments - Proposal is premature and too costly. Not a benefit to the customer at this point and time. Ask PSC consider needs of individuals.
9:05:47 AM	Chairman	
	Note: Fields, Angela	Mckenzie filed a comment in trec
9:06:16 AM	Jack Morris	
	Note: Fields, Angela	Public Comments. In support of the proposal.
9:09:02 AM	Chairman	
	Note: Fields, Angela	Any pending motions?
9:09:37 AM	KU/LG&E - direct Malloy	
	Note: Fields, Angela	Who are you employed?
9:10:35 AM	KU/LG&E - Malloy	
	Note: Fields, Angela	Answers be the same?
9:10:53 AM	AG - cross Malloy	
	Note: Fields, Angela	Handing out exhibits. AG Exhibits 1 through 10.
9:12:26 AM	AG - Malloy	
	Note: Fields, Angela	Application is for CPCN?
9:12:57 AM	AG - Malloy	
	Note: Fields, Angela	Advanced metering systems.
9:13:15 AM	AG - Malloy	
	Note: Fields, Angela	Few years left on the meters in service correct? Undepreprecíated average is 15 years?
9:13:45 AM	AG - Malloy	
	Note: Fields, Angela	Business case, the indepth benefit analysis.
9:14:34 AM	AG - Malloy	
	Note: Fields, Angela	Per update of July 3rd, benefit is 24.6 million?
9:15:23 AM	AG - Malloy	
	Note: Fields, Angela	Compare to 24.6 million number to the chart below it.
9:16:00 AM	AG - Malloy	
	Note: Fields, Angela	What service life of the meters does the 24.6 million represent?
9:17:08 AM	AG - Malloy	
	Note: Fields, Angela	The bottom chart is not a 23 year benefit period?

9:17:50 AM	AG - Malloy	
	Note: Fields, Angela	On average a 21.5 year service period for these meters?
9:18:43 AM	AG - Malloy	
	Note: Fields, Angela	The table at the bottom. When you calucated this, did you assume for the15 yr service life the benefits of the costs over 15 years the net present value revenue requirement?
9:19:32 AM	AG - Malloy	
	Note: Fields, Angela	You depreciated the meters over 18 years?
9:20:15 AM	AG - Malloy	
	Note: Fields, Angela	You assumed it would provide benefits for 18 years but paying them off in 15 years?
9:20:52 AM	AG - Malloy	
	Note: Fields, Angela	How is something expected to continue to have benefits after the useful life?
9:22:03 AM	VC Cicero	
	Note: Fields, Angela	Historical life established based on what the life is on those assets. Service life 13 to 15 years?
9:22:35 AM	VC Cicero	
	Note: Fields, Angela	Have a manufacture that say those meters will last 20 years?
9:23:29 AM	VC Cicero	
	Note: Fields, Angela	Service life and depreciation life that are substantially different.
9:24:26 AM	AG - Malloy	
	Note: Fields, Angela	Who is the risk on whether the benefits in the cost benefit analysis show up or not?
9:25:53 AM	AG - Malloy	
	Note: Fields, Angela	Exhibit 2 tab 2. Page 16, line 5. Are you aware of this testimony?
9:27:57 AM	AG - Malloy	
	Note: Fields, Angela	Current business plan assume a failure of half the meters in 15 years?
9:29:01 AM	AG - Malloy	
	Note: Fields, Angela	Instead of 8 years it is more than 5? Continue to provide benefits after 5 years of useful life of meters?
9:29:29 AM	AG - Malloy	
	Note: Fields, Angela	You are expecting them to last more than 20 years?
9:30:03 AM	AG - Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 3. You are the respondent to this correct?
9:30:27 AM	AG - Malloy	
	Note: Fields, Angela	Did you change that 15 year depreciation for either of the responses?
9:31:54 AM	AG - Malloy	
	Note: Fields, Angela	Malloy direct testimony on page 21, line 15. Inform the Commission of your response was. Was it reasonable?
9:32:55 AM	AG - Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 4. Company response to Commission Staff 1-9.
9:33:41 AM	AG - Malloy	
	Note: Fields, Angela	Email thread betwee a Paul, Tim and Jonathon Whitehouse
9:34:06 AM	AG - Malloy	
	Note: Fields, Angela	Does it indicate anywhere on this email Tim and Paul work?
9:34:41 AM	AG - Malloy	
	Note: Fields, Angela	Any authentication or signature from Tim?
9:35:04 AM	AG - Malloy	
	Note: Fields, Angela	In response to question that said provide any data relied upon?
9:36:00 AM	AG - Malloy	
	Note: Fields, Angela	Based on the two tables together there is no way it is a 20 year service life because it would be less.

9:36:14 AM	AG - Malloy	
	Note: Fields, Angela	Move to strike this attachment as hearsay. No authentication who it is from.
9:36:46 AM	Atty Duncan - KU/LG&E	
	Note: Fields, Angela	the Company provided that information. This is the data upon which the company relied.
9:37:34 AM	Chairman	
	Note: Fields, Angela	Overruled.
9:37:56 AM	AG - Malloy	
	Note: Fields, Angela	This response goes to the conversation we had earlier about the difference between actualized and depretionalized?
9:38:20 AM	AG - Malloy	
	Note: Fields, Angela	Should we depend the service life of the companys' put forward or accounting service life?
9:39:00 AM	AG - Malloy	
	Note: Fields, Angela	Your depreciation expert set forth what he thought was the deprectiation life of the meters?
9:39:37 AM	AG - Malloy	
	Note: Fields, Angela	Malloy testimony, second part to A. Page 21-24.
9:40:29 AM	AG - Malloy	
	Note: Fields, Angela	In discussing a 20 years useful life of the meters. Amberan(?), IL, cost benefit analysis. Is that your position?
9:41:42 AM	AG - Malloy	
	Note: Fields, Angela	Are you anticipating a 8 year depreciation period?
9:42:16 AM	AG - Malloy	
	Note: Fields, Angela	Con Ed had a six year project life and a five year meter deployment scenerio. Did you have a five year deployment scenerio?
9:42:44 AM	AG - Malloy	
	Note: Fields, Angela	Sister regulator same as the PSC except in OH. OH used 20 year benefit period and assumed a 20 year useful life for AMI meters.
9:43:06 AM	AG - Malloy	
	Note: Fields, Angela	Are the utilities in this case basing their cost benefit analysis on a 20 year useful life and a 20 year benefit period?
9:44:00 AM	AG - Malloy	
	Note: Fields, Angela	So you have a 23 year benefit period?
9:44:38 AM	AG - Malloy	
	Note: Fields, Angela	You assumed a longer than 20 year service life?
9:45:01 AM	AG - Malloy	
	Note: Fields, Angela	Do you know how long the meters lasted in OH?
9:46:16 AM	AG - Malloy	
	Note: Fields, Angela	Your understanding that the meters in Duke, OH did not last 20 years?
9:47:30 AM	AG - Malloy	
	Note: Fields, Angela	The OH audit was in 2011?
9:47:52 AM	AG - Malloy	
	Note: Fields, Angela	Refer to Malloy rebuttal testimony at page 8, line 14.
9:49:41 AM	AG - Malloy	
	Note: Fields, Angela	You picked the 20 years from that study but the rest of the analysis was of limited usefulness?
9:50:34 AM	AG - Malloy	
	Note: Fields, Angela	Direct on page 23, line 11. You said Duke used a 20 year service life period. That is not what the company has here?
9:51:40 AM	AG - Malloy	
	Note: Fields, Angela	Maine study. They approved a AMI project based on a 20 year cost benefit period.

9:52:11 AM	AG - Malloy	
	Note: Fields, Angela	Non-IOU cost benefit analysis based on BC Hydro.
9:52:47 AM	AG - Malloy	
	Note: Fields, Angela	Risks. The companys' proposal assume you recover over 15 years. Is it your opinion the majority of the capital and other costs are weighted more heavily toward the front end?
9:54:15 AM	AG - Malloy	
	Note: Fields, Angela	Pg 21-14 response for 20 years. How many studies that we went through assumed a service life of beyond 20 years?
9:55:02 AM	AG - Malloy	
	Note: Fields, Angela	All these studies support, but we are going a little longer in the service life.
9:55:49 AM	AG - Malloy	
	Note: Fields, Angela	Where in the record did the company provide alternatives to the business case?
9:57:40 AM	AG - Malloy	
	Note: Fields, Angela	You set the parameters and this was the only study that would apply?
9:58:19 AM	AG - Malloy	
	Note: Fields, Angela	You would agree that the conservation efforts are a very small part of the cost benefit analysis?
9:59:00 AM	AG - Malloy	
	Note: Fields, Angela	Where in the record is any conversations about alternatives?
9:59:50 AM	AG - Malloy	
	Note: Fields, Angela	Can the customers get a smart meter right now?
10:00:07 AM	AG - Malloy	
	Note: Fields, Angela	Had for ten years, not fully subscribed and limited to 10 thousand?
10:00:41 AM	AG - Malloy	
	Note: Fields, Angela	If you didn't look at alternatives how do you know this is the most cost beneficial alternative?
10:01:24 AM	AG - Malloy	
	Note: Fields, Angela	How do you know if this is the least cost alternative?
10:02:20 AM	AG - Malloy	
	Note: Fields, Angela	Malloy Direct testimony, page 24, line 11. How did the company account for the costs of retiring the meters in the cost benefit analysis?
10:04:22 AM	AG - Malloy	
	Note: Fields, Angela	AG Exhibit 5, pg 75.
10:06:21 AM	AG - Malloy	
	Note: Fields, Angela	6th line under section D. That question is a little different then what the attorney asked you in your direct testimony.
10:08:23 AM	AG - Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 6. Filed by KU/LG&E on Feb. 22, 2015 styled as joint brief.
10:09:02 AM	AG - Malloy	
	Note: Fields, Angela	Under Section G - cost recovery. And you think that response is consistent to what you did in this case?
10:10:28 AM	AG - Malloy	
	Note: Fields, Angela	How long have you been with the utility business? Majority with the KU/LG&E?
10:12:42 AM	AG - Malloy	
	Note: Fields, Angela	Pg 29 in Malloy rebuttal testimony.
10:13:07 AM	AG - Malloy	
	Note: Fields, Angela	The question was "Do you agree" with Mr. Alvarez? You said you believe the opposite is true. Is that correct?

10:13:59 AM	AG - Malloy	
	Note: Fields, Angela	Is the company economically penalized if the customers use less?
10:14:29 AM	AG - Malloy	
	Note: Fields, Angela	Mr. Seely? Consistently been he cost of service expert for the companies?
10:14:47 AM	AG - Malloy	
	Note: Fields, Angela	Refer AG Exhibit 7, pg. 8. Direct testimony of Seely.
10:16:04 AM	AG - Malloy	
	Note: Fields, Angela	Do you agree with him (Seely)?
10:17:07 AM	AG - Malloy	
	Note: Fields, Angela	Program paid for by all customers but it only benefits the customers that participate?
10:18:13 AM	AG - Malloy	
	Note: Fields, Angela	That is why you have a cost recovery mechanism in DSM?
10:18:48 AM	AG - Malloy	
	Note: Fields, Angela	Did they do it from aspect of company or customers?
10:19:19 AM	AG - Malloy	
	Note: Fields, Angela	Capital costs in the next rate case?
10:20:27 AM	AG - Malloy	
	Note: Fields, Angela	The company does have an expectation
10:20:56 AM	AG - Malloy	
	Note: Fields, Angela	The cost benefit analysis assumes everything at the end of the year?
10:21:30 AM	AG - Malloy	
	Note: Fields, Angela	In rebuttal, it would be a benefit to customers if company keeps the benefits and delay the rate case.
10:22:21 AM	AG - Malloy	
	Note: Fields, Angela	You think Customers would rather have a delay in rate cases or more cash in their pockes?
10:22:51 AM	AG - Malloy	
	Note: Fields, Angela	The company is in full control of revenue between rate cases?
10:23:31 AM	AG - Malloy	
	Note: Fields, Angela	Are you aware of Amberan(?) cost benefit analysis? Refer to AG Exhibit 8.
10:24:26 AM	AG - Malloy	
	Note: Fields, Angela	Used the Amberan cost benefit analysis in support of your cost benefit analysis correct?
10:26:04 AM	AG - Malloy	
	Note: Fields, Angela	It is assuming perfect rate treatment.
10:26:41 AM	AG - Malloy	
	Note: Fields, Angela	You didn't do the IRR test or the TRC analysis?
10:27:18 AM	AG - MalloyAG - Malloy	
	Note: Fields, Angela	How you calculated those e-portal benefits. Pg 18 line 12 of Malloy testimony.
10:28:11 AM	AG - Malloy	
	Note: Fields, Angela	Average of data from other utilities that has similar opt-outs.
10:28:30 AM	AG - Malloy	
	Note: Fields, Angela	How did you define active users?
10:29:06 AM	AG - Malloy	
	Note: Fields, Angela	17% reflects those that chose to opt in to having these meters.
10:29:36 AM	AG - Malloy	
	Note: Fields, Angela	Do you think these are dedicated individuals to conservation?

10:31:24 AM	AG - Malloy	
	Note: Fields, Angela	Do you believe you are more energy conservative than average customer?
10:32:27 AM	Session Paused	
10:46:29 AM	Session Resumed	
10:46:38 AM	AG - Malloy	
	Note: Fields, Angela	Pg18 direct testimony. 17% are active users, determined based off a 48% number. Do you know what the 48% number was?
10:48:01 AM	AG - Malloy	
	Note: Fields, Angela	17% who wanted the meters logged in at least six times. 17% was applied to the entire customer base.
10:48:40 AM	AG - Malloy	
	Note: Fields, Angela	You took other 99.2% of customers and assumed that the 17% of those that opted-in would apply to the entire customer base?
10:49:27 AM	AG - Malloy	
	Note: Fields, Angela	Reasonable to assume that those that who opted-in are more dedicated to energy conservation?
10:50:46 AM	AG - Malloy	
	Note: Fields, Angela	1/2 percent is a conservative estimate?
10:51:15 AM	AG - Malloy	
	Note: Fields, Angela	How is that conservative?
10:53:20 AM	AG - Malloy	
	Note: Fields, Angela	3% is based on a smart grid.
10:53:43 AM	AG - Malloy	
	Note: Fields, Angela	E-portal like systems?
10:54:05 AM	AG - Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 9, pg 32 of 61.
10:55:12 AM	AG - Malloy	
	Note: Fields, Angela	Some utilies do a comparison with neighbors. Provide that service?
10:56:24 AM	AG - Malloy	
	Note: Fields, Angela	Historical or real-time data in intervals?
10:57:13 AM	AG - Malloy	
	Note: Fields, Angela	Offer customers have access to historical usage on a one day lag?
10:59:42 AM	AG - Malloy	
	Note: Fields, Angela	E-portal benefits are based on consumption conservation study?
11:00:23 AM	AG - Malloy	
	Note: Fields, Angela	You are not offering realtime feedback?
11:01:33 AM	AG - Malloy	
	Note: Fields, Angela	Using a 5 to 15% data point that is not comparible to what you are doing.
11:03:08 AM	AG - Malloy	
	Note: Fields, Angela	You are providing people after the fact data and in support of that assumption you provided this study?
11:03:34 AM	AG - Malloy	
	Note: Fields, Angela	Show me where historical usage data provides 3% in savings
11:04:45 AM	AG - Malloy	
	Note: Fields, Angela	Prius(?) effect?
11:07:13 AM	AG - Malloy	
	Note: Fields, Angela	You have to spend money to save money.
11:08:20 AM	AG - Malloy	
	Note: Fields, Angela	Direct real time usage feed back. It is telling you how much you are using. That is what this study was talking about.

11:09:24 AM	AG - Malloy	
	Note: Fields, Angela	Are the eportal benefits assumed based on customers using real time data?
11:10:45 AM	AG - Malloy	
	Note: Fields, Angela	Savings were predicated on real time usage feed back?
11:11:51 AM	AG - Malloy	
	Note: Fields, Angela	You are not providing your customers with realtime usage feed back?
11:14:25 AM	AG - Malloy	
	Note: Fields, Angela	You are assuming real time feed back and that is what the study was predicated on?
11:14:46 AM	Chairman Schmitt	
	Note: Fields, Angela	You made your point.
11:15:11 AM	AG - Malloy	
	Note: Fields, Angela	Nominal savings in e-portal benefits are just over 100 million.
11:16:02 AM	AG - Malloy	
	Note: Fields, Angela	Non technical losses.
11:16:37 AM	AG - Malloy	
	Note: Fields, Angela	When you say conservative, wouldn't you say more than half of the kW added charge included fixed cost to the company?
11:17:14 AM	AG - Malloy	
	Note: Fields, Angela	When you come back into a rate case, 71% of savings are likely to disappear after rate case.
11:18:42 AM	VC Cicero	
	Note: Fields, Angela	Rate making process fixed costs will have to be covered.
11:18:43 AM	Camera Lock Intervenor Activated	
11:18:49 AM	Camera Lock Deactivated	
11:19:08 AM	Camera Lock Panel Wide Activated	
11:19:21 AM	Camera Lock Deactivated	
11:19:26 AM	Camera Lock Panel Wide Activated	
11:19:28 AM	VC Cicero	
	Note: Fields, Angela	Fixed costs are going to be spread over a lower volumn.
11:19:38 AM	Camera Lock Deactivated	
11:20:28 AM	AG - Malloy	
	Note: Fields, Angela	Assume that 2% of total revenue is lost each year on nontechnical losses?
11:21:37 AM	AG - Malloy	
	Note: Fields, Angela	60% estimate of identified bill is based on conversations with other utilities?
11:22:03 AM	AG - Malloy	
	Note: Fields, Angela	Theft portion. Did you calculate that amount net of detection and prosecution?
11:23:16 AM	AG - Malloy	
	Note: Fields, Angela	Assume or calculate there would not be any additional costs?
11:23:50 AM	AG - Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 9. Revenue assurance.
11:26:21 AM	AG - Malloy	
	Note: Fields, Angela	How much in theft the company recovered in 2017?
11:27:29 AM	AG - Malloy	
	Note: Fields, Angela	Pg 18 in direct testimony. Tampring fees and bills.
11:28:25 AM	AG - Malloy	
	Note: Fields, Angela	It costs the company 50 cents for every dollar it recovers for theft?

11:29:22 AM	AG - Malloy		
		Note: Fields, Angela	Zero incremental costs to identifing and billing 400 million over a 23 yr period?
11:31:23 AM	AG - Malloy		
		Note: Fields, Angela	You did not include any incrimental costs to collect 17.5 million?
11:32:39 AM	AG - Malloy		
		Note: Fields, Angela	Zero dollars assumed for collection costs.
11:33:35 AM	AG - Malloy		
		Note: Fields, Angela	Theft largest part of nontechnical losses?
11:34:06 AM	VC Cicero		
		Note: Fields, Angela	You are going to start up a meter operation center and costs are included in this project.
11:35:10 AM	VC Cicero		
		Note: Fields, Angela	PHDR - what catagory are they included?
11:35:41 AM	AG - Malloy		
		Note: Fields, Angela	Pg 16 of testimony. Line 12. Half of the nontechnical loss is caused by theft?
11:37:44 AM	AG - Malloy		
		Note: Fields, Angela	Are there incremental billing costs?
11:38:50 AM	AG - Malloy		
		Note: Fields, Angela	Do they know there are going to get about 12 times more work?
11:39:29 AM	AG - Malloy		
		Note: Fields, Angela	Average meter tampering charges and unbilled amounts.
11:41:56 AM	AG - Malloy		
		Note: Fields, Angela	Prudent to look at that when dealing with incremental costs of billing and collections might be?
11:43:01 AM	AG - Malloy		
		Note: Fields, Angela	You didn't consider what the incremental costs would be?
11:45:03 AM	AG - Malloy		
		Note: Fields, Angela	You will be pulling meters quicker than before?
11:45:37 AM	AG - Malloy		
		Note: Fields, Angela	The company's estimate is effectively at .72% billed and collected, and that number is gross?
11:46:15 AM	AG - Malloy		
		Note: Fields, Angela	That estimate is not far appart from the extimate that Alvarez estimated in the 2016 rate case?
11:47:43 AM	AG - Malloy		
		Note: Fields, Angela	Refer to Pg 36 of Malloy rebuttal, line 3.
11:48:57 AM	AG - Malloy		
		Note: Fields, Angela	Is it unreasonable to average that range?
11:50:32 AM	AG - Malloy		
		Note: Fields, Angela	They are at least 20% different.
11:51:10 AM	AG - Malloy		
		Note: Fields, Angela	Might change the cost benefit analysis to be negative?
11:51:50 AM	AG - Malloy		
		Note: Fields, Angela	Refer to AG Exhibit 9, Pg. 31 of 61. Economic benefit of revenue assurance.
11:53:08 AM	AG - Malloy		
		Note: Fields, Angela	That amount does seem conservative when compared to the company number?.
11:54:10 AM	AG - Malloy		
		Note: Fields, Angela	If company after the 15 year service life, is there any risk on the company that was estimated; have they come about?

11:55:53 AM	AG - Malloy	
	Note: Fields, Angela	Financial risk.
11:58:32 AM	AG - Malloy	
	Note: Fields, Angela	After the meters are fully decrepiated, the financial risks are on the customers?
12:00:14 PM	AG - Malloy	
	Note: Fields, Angela	Replacing with new ones that are net cost beneficial?
12:00:58 PM	AG - Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 10. Estimated cost to customer for real time data. Missing key between proposal and providing real time data.
12:03:04 PM	Session Paused	
1:00:37 PM	Session Resumed	
1:01:20 PM	Atty Skidmore - CAC	
	Note: Fields, Angela	Excuse witness, Mr. Ratchford?
1:02:11 PM	Atty Crosby - LG/KU	
	Note: Fields, Angela	Wanted to provide a citation to avoid a to avoid PHDR.
1:03:45 PM	Atty Chandler -	
	Note: Fields, Angela	Introduced AG Exhibits 1-10.
1:04:04 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Handed out ACM Exhibits 1-3. Pg 55, jpm 1. 42 is 1, 38 is 2, 32 is 3.
1:06:34 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	8.2 Major IT system releases. Pg. 56, Release 2 at bottom third of page.
1:07:23 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Does that include remote disconnections for nonpayment?
1:07:57 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Pg 53 of ACM Exhibit 1. Timeline. Indicating the start of remote service?
1:09:14 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Remote disconnection would not start till 2019?
1:10:00 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	When do you anticipate when remote disconnection for nonpayment will start?
1:11:38 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	No estimated start date?
1:12:32 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	ACM Exhibit 1. When would you expect to have enough designed to know how that will work?
1:13:49 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	How far in advance would you need to know how it works?
1:14:45 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	ACM Exhibit 2, question 38. How would the disconnection process change?
1:16:42 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	When do you think that design process will be complete?
1:18:58 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	When would you expect to know when this is going to work?
1:20:13 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Last question. At least six months before you roll it out?
1:20:52 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Current process for disconection. After remote disconnection begins will the companies have the ability to disconnect all customers eligible on the save day?

1:23:33 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	The companies have not made a final decision on the timing?
1:24:00 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	ACM Exhibit 3. How would the disconnection processs go for those with serious medical issues. Medical Alert Program?
1:26:27 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Anticipate after remote disconnection that field service tech would go out to do the disconnection?
1:27:41 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Malloy Rebuttal testimony on, pg. 54. Low income assistance agencies.
1:29:58 PM	Atty Kilkelly - cross Malloy	
	Note: Fields, Angela	Tranches. Geographic areas?
1:31:40 PM	Atty Fitzgerald MHC - cross Malloy	
	Note: Fields, Angela	Are the proposed meters referred to a AMI meters?
1:32:26 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	What will the total costs be for the residential customer after the deployment?
1:33:24 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Initial years of the program increases are we looking at 2.70 on monthly bill?
1:33:53 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	What period will you spread that cost?
1:34:31 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Proposed montly savings that you are anticipating for the average customer?
1:34:56 PM	Atty Crosby	
	Note: Fields, Angela	He is referring to 2nd round of AG requests, Attachment 2, 14A
1:37:36 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	How much does each customer pay on a monthly basis for the current meters?
1:37:50 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	How many years will they continue paying for that?
1:38:20 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	What a AMR?
1:39:03 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Do you have to drive by to get the reading or can you do it remotely?
1:39:56 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Three areas of savings. Operational, nontechnical, and saving from customers that were implementing coservation efforts. AMR allows for similar outcomes?
1:41:29 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Cost woulld of deploying AMR as opposed to the new system?
1:42:00 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Cost of new meters relative to the old meters?
1:42:25 PM	New Event	
	Note: Fields, Angela	Is the company proposing to install a new generation of meters while disposing of functioning meters?
1:44:08 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Due to a monoply in the service area, meter readers will not be able to get a similar employment reading someone else's meters?
1:45:47 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	How many jobs will be lost due to the AMS deployment?

1:47:05 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Intend to retrain readers for the new jobs?
1:47:25 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Malloy rebuttal at pg. 19. Does it take 5 years to determine if a smart meter is defective?
1:47:32 PM	Camera Lock PTZ Activated	
1:47:41 PM	Camera Lock Deactivated	
1:48:55 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	How long is the index guarenteed for?
1:50:01 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	What percentage of meters had to be replaced?
1:50:31 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Meter being used in the pilot program the same?
1:51:58 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Could you still get the benefit of operational savings if you used a meter that does not have remote disconnect?
1:52:21 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Model of meter deploying. Are there studies on useful life once deployed?
1:53:31 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Where do you project the energy savings to come from when you deploy the new system?
1:55:30 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Do you know if the customers did by reducing the savings?
1:56:08 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Costomers in the pilot are more motivated to conserve?
1:56:53 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Pg 46 of rebuttal. Cost of new meters should be paid by the customers. Did you advise Commission that you would remove and scrap the meters before end of their useful life?
1:58:44 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Possible the company will sell the usage data collected under the AMS?
1:59:20 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Privacy. Release of subpoenas?
2:01:09 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	All were paying even though about 10 thousand would benefit from it?
2:02:43 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Customers are currently unaware of how much energy they are using?
2:03:18 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Opt out rate of .8 percent?
2:03:52 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Risk comparison between both programs and what you are proposing?
2:04:27 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Percentage that opted out. Reasons why they opted out?
2:05:57 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Will the customers recognize the benefits from day one?
2:07:23 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Whether opt out charges will be eligible for low income assistance?
2:08:11 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Did the people who participated in the program high income or low income?

2:08:31 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	You critized Hinko's testimony about replacing the first generation meters.
2:09:36 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Malloy rebuttal testimonyt pg 24. Committee offering alternative benefits in the future.
2:10:44 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Cost benefits. Costs will not exceed what was projected?
2:11:30 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Why not commit to not seeking to recover anything above the project cost what was projected?
2:12:42 PM	Atty Fitzgerald - cross Malloy	
	Note: Fields, Angela	Are you willing to commit to the benefits projected?
2:13:58 PM	Atty Vinsel PSC - cross Malloy	
	Note: Fields, Angela	Costs re: connections and disconnections. Any consideration about a delay in the implementing the remote disconnect and the impact?
2:16:11 PM	Commissioner Mathews	
	Note: Fields, Angela	Further consideration built into the business case?
2:16:37 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	No alternatives were identified. Alternatives for implementing a phased-in program for a discreet period of time?
2:18:55 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	The selection criteria for AMI was not included the case?
2:19:53 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	Handing out documents for meter operation center. Pg 49 of Exhibit JPM -1 the business case.
2:20:54 PM	VC Cicero	
	Note: Fields, Angela	Refer to JPM-1, Appendix A-5, pg 4.
2:21:48 PM	VC Cicero	
	Note: Fields, Angela	For 2018-2022. If the O&M cost is 29.8 million, how can MOC costs be included in this program?
2:22:38 PM	VC Cicero	
	Note: Fields, Angela	Ongoing operation costs is 37 million. How does that figure into the 29.8 millin in four years?
2:23:46 PM	VC Cicero	
	Note: Fields, Angela	What is the total cost of the project?
2:26:11 PM	VC Cicero	
	Note: Fields, Angela	PHDR - breakdown of the 108.
2:27:22 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	Why would installing the system now, instead of 15 years from now when the meters reach their useful life. Why do this now?
2:28:58 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	Nested outages. Outages that have not been reported?
2:31:03 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 4. Response to Staff item 9.
2:32:34 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	Any further discussion with Hilton about this?
2:33:22 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	Refer to AG Exhibit 1. Referring to the TCJA adjustments. What other adjustments were included?
2:34:54 PM	Atty Vinsel - cross Malloy	
	Note: Fields, Angela	Excess deferred income tax. Reflect the lower tax rate?
2:35:35 PM	VC Cicero	
	Note: Fields, Angela	Landis & Gry. Something from the manufacturer that speaks to the 20 year life?

2:38:00 PM	VC Cicero	
	Note: Fields, Angela	It is moot, because you have already submitted you application. Need something more than an email on the useful life on the meter.
2:40:11 PM	VC Cicero	
	Note: Fields, Angela	If you postponed it and staggared implemenation wouldn't it be an easier way to make sure the benefits received from the rate payers would be more assured rather than strand all these assets?
2:42:55 PM	VC Cicero	
	Note: Fields, Angela	How do you jump to the extra three years?
2:44:09 PM	VC Cicero	
	Note: Fields, Angela	Any projects were the benefit exceeds the useful life of the asset that is being implemented?
2:46:40 PM	Commissioner Mathews	
	Note: Fields, Angela	Did you look at the two companies individually or together?
2:47:01 PM	Commissioner Mathews	
	Note: Fields, Angela	Do enough analysis to see if there was more benefit from one company then the another?
2:47:27 PM	Commissioner Mathews	
	Note: Fields, Angela	If customers wanted third parties to have access to their data would you give them access?
2:49:07 PM	Commissioner Mathews	
	Note: Fields, Angela	Considering a prepay for customers?
2:49:39 PM	Commissioner Mathews	
	Note: Fields, Angela	Would a prepay increase or decrease the benefits that roll out of the AMI?
2:50:46 PM	Commissioner Mathews	
	Note: Fields, Angela	How many additional AMI meters have been installed in the past five years? How fast is this technology advancing?
2:52:09 PM	Commissioner Mathews	
	Note: Fields, Angela	AMI series 1 vs. AMI series 5. How fast is the AMI technology changing?
2:53:55 PM	Commissioner Mathews	
	Note: Fields, Angela	For the last rate case, you did some automated distribution system upgrades?
2:55:36 PM	Commissioner Mathews	
	Note: Fields, Angela	Have you built out a network that is going to be used for AMI?
2:56:35 PM	Session Paused	
3:11:41 PM	Session Resumed	
3:11:53 PM	Atty Chandler - direct Alvarez	
3:12:02 PM	Chaiman	
	Note: Fields, Angela	Taking a witness out of turn. Other witnesses, ACM witness are excused.
3:13:22 PM	Atty Chandler - direct Alvarez	
	Note: Fields, Angela	Name and business address.
3:13:46 PM	Atty Chandler - direct Alvarez	
	Note: Fields, Angela	Direct testimony and data requests in this matter?
3:14:35 PM	Atty Vinsel PSC - cross Alvarez	
	Note: Fields, Angela	Previous study of Duke Energy, OH. In that case you used a 20 year service life?
3:15:33 PM	Atty Vinsel PSC - cross Alvarez	
	Note: Fields, Angela	Why should the cost of the existing meter be included in the cost benefit analysis?
3:18:10 PM	Atty Vinsel PSC - cross Alvarez	
	Note: Fields, Angela	Duke energy OH. What was the deployment period was?

3:19:45 PM	Atty Chandler - redirect Alvarez	
	Note: Fields, Angela	Do you know how long those meters lasted.
3:20:10 PM	Atty Chandler redirect Alvarez	
	Note: Fields, Angela	OH PUC deployment. A 20 yr benefit period there is comparible to their 23 year benefit in this case?
3:21:07 PM	Atty Chandler redirect Alvarez	
	Note: Fields, Angela	What LG&E/KU are proposing is a 20 year service life in their cost benefit analysis?
3:22:50 PM	Atty Crosby - cross Alvarez	
	Note: Fields, Angela	Handing out document. LG&E/KY Exhibit 1
3:24:36 PM	Atty Crosby - cross Alvarez	
	Note: Fields, Angela	Indicate to you that the meter life would be 20 years?
3:25:39 PM	Atty Crosby - cross Alvarez	
	Note: Fields, Angela	Handing out document. LG&E/KU Exhibit 2.
3:26:49 PM	Atty Crosby - cross Alvarez	
	Note: Fields, Angela	At that time the service life could be 20 years or more?
3:27:00 PM	Atty Crosby - cross Alvarez	
	Note: Fields, Angela	Exhibits admitted.
3:27:07 PM	Chairman	
	Note: Fields, Angela	Entered exhibits. Meter operations exhibit 1,
3:27:49 PM	Atty Chandler - redirect Alvarez	
	Note: Fields, Angela	Did you pick the 20 years in the Duke case?
3:28:24 PM	Atty Chandler - redirect Alvarez	
	Note: Fields, Angela	How about Excel? You did not pick the 20 years in either case?
3:29:22 PM	Atty Chandler - redirect Alvarez	
	Note: Fields, Angela	Read Mr. Malloy's rebuttal in this case?
3:30:03 PM	Atty Vinsel - cross Alvarez	
	Note: Fields, Angela	Is it the same type in the Duke case as the meter proposed in this case?
3:30:32 PM	Atty Chandler - cross Alvarez	
	Note: Fields, Angela	for the smart grid city demonstration?
3:31:10 PM	Atty Crosby - direct Lovekamp	
	Note: Fields, Angela	Name and address
3:31:49 PM	Atty Crosby - direct Lovekamp	
	Note: Fields, Angela	Familiar with the updates filed
3:33:00 PM	Atty McNeil AG - cross Lovekamp	
	Note: Fields, Angela	Wouldn't more expensive meters increase the service charge?
3:33:36 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	Those costs may or may not be proportional to any reduced cost on the other side?
3:34:27 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	Tariff provisions proposed, provide any for a customer to purchase device to access their data in realtime?
3:35:09 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	Zigby technology?
3:35:40 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	Is that in the tariff you proposed. Option for inhome devises that customers can purchase on their own?
3:36:07 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	If approved would you provide more info to customers?
3:36:25 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	Refer to LoveKamp testimony, Exhibit REL 1. Chart Justification at the top.

3:37:50 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	Everythng in the five year life will be replaced?
3:38:15 PM	Atty McNeil AG -cross Lovekamp	
	Note: Fields, Angela	In home displays. Providing help for installations?
3:39:31 PM	Atty KilKelly - cross Lovekamp	
	Note: Fields, Angela	Pg. 5 of Lovekamp testimony. Elaborate on how will this improve the speed?
3:40:10 PM	Atty KilKelly - cross Lovekamp	
	Note: Fields, Angela	Do you suspect it will improve speed of disconnections?
3:40:30 PM	Atty KilKelly - cross Lovekamp	
	Note: Fields, Angela	You think it would be possible to improve the speed?
3:41:12 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	Familiar with the AMS pilot program?
3:41:53 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	Unsure of whether there would be energy savings?
3:42:13 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	Filed approval of the DSM since 2014?
3:43:18 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	How can they suggest 3% savings? Is that something you are not willing to recover?
3:44:15 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	Has the company projected the net present value of the AMS deployment to shareholders?
3:44:57 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	Who bears the risks of those losses?
3:47:22 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	Did you include the cost of replacing the existing gas meters?
3:48:20 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	8% of customers would choose to opt out. How did you come to 8%?
3:49:13 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	The cost you are proposing is base on the 8%?
3:49:48 PM	Atty Fitzgerald MHC - cross Lovekamp	
	Note: Fields, Angela	Remove benefits in the proposed CPCN, do the benefits exceed the cost over the projected 20 years?
3:51:00 PM	VC Cicero	
	Note: Fields, Angela	Refer to Malloy testimony, Break down of O&M costs.
3:52:16 PM	VC Cicero	
	Note: Fields, Angela	Verify at bottom of page shows 108.8 million?
3:52:50 PM	VC Cicero	
	Note: Fields, Angela	2023-2040 - Interested of ongoing cost, because 37 million is an ongoing annual cost. I want to see where that is. .
3:53:24 PM	Commissioner Mathews	
	Note: Fields, Angela	On your optout cost on gas and electric, how many customers do you have that are both gas and electric?
3:55:12 PM	Commissioner Mathews	
	Note: Fields, Angela	If I am on both am I not paying over a $100 for opt out, and $43 a month for the opt out?
3:55:53 PM	Atty Crosby - redirect	
	Note: Fields, Angela	VC Cicero's questions about the 37 million operation center costs?
3:56:17 PM	Atty Crosby - redirect	
	Note: Fields, Angela	2nd paragraph . Do you understand that to be an annual cost or the total of annual ongoing costs?

3:57:11 PM	VC Ciceroo	
	Note: Fields, Angela	You need to clarify if is annual or not.
3:58:27 PM	Atty Crosby - direct Huff	
	Note: Fields, Angela	Name and address.
3:58:38 PM	Atty Crosby - direct Huff	
	Note: Fields, Angela	Are you familiar with the updates in this proceding?
3:58:48 PM	Atty Crosby - direct Huff	
	Note: Fields, Angela	Answers be the same?
3:59:14 PM	Atty Crosby - direct Huff	
	Note: Fields, Angela	Refer to the Malloy JPM1. pg 49
4:00:06 PM	Atty Crosby - direct Huff	
	Note: Fields, Angela	Is the 37 million of ongoing costs of the meter operation center an annual cost?
4:00:24 PM	Atty Crosby - direct Huff	
	Note: Fields, Angela	Annual O&M cost or total cost over the time period?
4:00:59 PM	Atty Crosby - direct Huff	
	Note: Fields, Angela	Refer to response to AG in 13.
4:02:02 PM	VC	
	Note: Fields, Angela	So it starts at 2025?
4:02:30 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	Displays with Zigby technology available to customers?
4:03:58 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	Products available in a range of price points?
4:04:59 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	Would the company permit customers to buy those devices from other sources?
4:05:48 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	Specifics on how that would rollout?
4:08:01 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	How will customers know how to install the displays?
4:09:05 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	You will make it known how that process will will work?
4:09:58 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	Anticipated having employees trained to help with the process?
4:11:39 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	If that project is approved, will it be reflected in the tariff?
4:12:13 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	AMS collaberative. What the companies expect to get out of the AMS collaborative?
4:14:13 PM	Atty McNeil AG - cross Huff	
	Note: Fields, Angela	Primary goal to was to inform and educate the participants?
4:19:36 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Are you familiar with the pilot AMS program?
4:20:18 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Do you have data now?
4:21:20 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	What percentage of AMS meters had to be replace in the program?
4:21:50 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Deployment may extend the period between rate cases.
4:22:03 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	If approved they will stay out of a rate increase for a period of time?

4:22:32 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Company not committing to stay out of rate case for a period of time?
4:23:21 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Are AMRs have the ability to be remotely read?
4:23:45 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Capable of alerting to any meter tampering?
4:24:05 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Meters in the pilot program did not have the remote disconnection?
4:24:27 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Aware of sensitivity of the remote disconnetion capability?
4:25:03 PM	Atty Fitzgerald - cross Huff	
	Note: Fields, Angela	Saving of not having to send meter readers
4:27:11 PM	Atty Skidmore CAC - cross Huff	
	Note: Fields, Angela	How are the companies intending to reach out to the low income advocates?
4:28:44 PM	Camera Lock PTZ Activated	
4:28:48 PM	Camera Lock Deactivated	
4:29:24 PM	Chairman	
	Note: Fields, Angela	PHDRs filed July 26th. respond by July 31. Briefing simutanous Aug. 10th.
4:33:30 PM	Session Paused	
4:34:27 PM	Session Ended	

Exhibit List Report

2018-00005 24July2018

LGE/KU AMS Meters CPCN

Judge: Bob Cicero; Talina Mathews; Michael Schmitt
Witness: Paul Alvarez; Michael Ashabraner; Cathy Hinko; David Huff; Rick Lovekamp; John Malloy; Malcolm Ratchford
Clerk: Angela Fields

Name:	Description:
ACM Exhibit 01	LG&E/KU Question No. 42 - Malloy
ACM Exhibit 02	LG&E/KU Question No. 38 - Malloy
ACM Exhibit 03	LG&E/KU Question No. 32 - Malloy
Attorney General Exhibit 01	Verified Information Update Filing
Attorney General Exhibit 02	Direct Testimony of John Spanos on Behalf of KU
Attorney General Exhibit 03	LG&E/KU Question No. 5 - Malloy
Attorney General Exhibit 04	LG&E/KU Question No. 9 - Malloy
Attorney General Exhibit 05	Letter to Jeff DeRouen from Rick Lovekamp dated June 30, 2014, with Attached Joint Report
Attorney General Exhibit 06	Letter to Jeff DeRouen from Rick Lovekamp dated February 27, 2015, with Attached Joint Brief
Attorney General Exhibit 07	Prepared Direct Testimony of William S. Seelye on Behalf of Columbia Gas of Kentucky, Inc.
Attorney General Exhibit 08	Deployment Map - Ameren, IL. Advanced Metering
Attorney General Exhibit 09	Revenue Assurance - Exhibit JPM-1, Appendix A-7 - Malloy
LG&E/KU Exhibit 01	Meter Operations Capital
LG&E/KU Exhibit 02	Lessons Learned will Optimize Furture Investments and Maximize PSCO Customer Value Pg. 6

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to the Association of Community Ministries, Inc.'s First Request for Information
Dated April 2, 2018

Case No. 2018-00005

Question No. 42

Witness: John P. Malloy

Q-42. Please refer to Exhibit DEH-6 at page 8, the second bullet point under the Remote Service Switch heading. Please describe in detail the plan to use a temporary procedure that has manual review and human intervention components for an initial period to fine tune any internal business logic and avoid unnecessary disconnections. If the plan has not been finalized, please describe options that the Companies are considering.

A-42. The temporary process is linked to the design and development of the Meter Data Management system and the remote service switch functionality which has not been designed. The intent of the temporary procedure is to assure the system design operates according to the Companies' disconnection and reconnection policies.

ASSOC. OF COMMUNITY MINISTRIES
EXHIBIT 1

  - The Collaborative discussed the principle that customers electing to opt-out prior to having their legacy meter exchanged for AMS meter should not be required to pay the one-time set-up fee.
- <u>Remote Service Switch</u>
  - Participants preferred disconnections to occur over a time range (e.g., 9 a.m. to noon) rather than all at once (e.g., 10 a.m.) to manage agencies' office traffic and support. With more certainty in disconnection timeframes, some participants suggested additional communications for disconnections based on customers' communication preferences. As discussed with the Collaborative participants, the Companies' future plans and processes are to increase education and awareness on service disconnections and to consider providing notice of disconnects through a variety of communication means such as text messages, phone calls, and mail.
  - The Companies confirmed to participants that they have no plans to change their current practices or programs. They plan to use a temporary procedure that has manual review and human intervention components for an initial period to fine-tune any internal business logic and avoid unnecessary disconnections. More specifically, the Companies are not proposing any disconnection-related revisions to the tariff terms and conditions of service from implementing AMS.
  - Participants approve of more flexibility for reconnections during non-standard business hours which would benefiting all (e.g., disconnections for non-payment, new customers, move-in).
  - Participants appreciated that the Remote Service Switch would be used for customer-scheduled disconnections, e.g. move-outs, but suggested there should be a minimum wait time for disconnection to prevent abuse, e.g., domestic disputes.
- New services:
  - Suggestions included enhancements to the ePortal "MyMeter" and systems to receive near-real-time usage information. Another participant suggested allowing customers to provide access to their MyMeter usage data by a customer-selected service provider to enable identification of energy- and cost-saving opportunities. Programs and services to support usage data that enable property managers and builders to improve properties and support financing for improvements were suggested. Some suggested deployment of in-home devices (IHD) to display usage information; however, the Companies stated that, due to the limited amount of time customers leave the device activated on their counter, IHD deployment was not cost effective.
- Education: Information needs to be communicated in multiple formats to all users and different comprehension levels across the customer base. The Companies agreed and plan communications similar to the success it has had with DSM.

Session 5: Refined Business Case discussion

The key objective of Session 5 was to review any updates the Companies had made to the initial business case for full deployment of AMS and better understand the estimated bill impacts to the customer. Discussion began with addressing additional questions on topics in previous sessions.

Discussion continued with an illustrative view of the estimated AMS cost per month per residential electric customer in the first five years (the graph). Participants found the information helpful and

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to the Association of Community Ministries, Inc.'s First Request for Information
Dated April 2, 2018

Case No. 2018-00005

Question No. 38

Witness: John P. Malloy

Q-38. Please refer to Exhibit DEH-4 page 33 entitled Current Disconnection Notice Process:

a. After the Companies implement remote disconnections, for each step on the chart, as well as any additional steps that may be added, please describe how the step will be carried out and by whom (e.g. personnel, contractor, other individuals or automated procedure including advanced meter.) For steps that will be carried out by personnel, contractors or other individuals, please identify the job title. For steps that will be carried out by automated procedure, including advanced meter, please describe the procedure. Please specify any steps that will require personnel, contractors or other individuals to enter information in the CIS or other Company systems.

b. After the Companies implement remote disconnections, please describe how and by whom (e.g. personnel, contract or other individual or automated procedure) payment information will be entered into the CIS or other Company system so that the Companies will know whether payment has been received within 16 days after the bill being sent or 10 days after the Brown Bill being sent or before the service technician gets to the disconnection location.

c. After the Companies implement remote disconnections, please describe how and by whom (e.g. personnel, contractor, other individuals or automated procedure.) information that would affect the disconnection process (such as a customer having an appointment with an assistance agency, pledge being made, certificate of need, payment plan or medical certificate) will be entered into the CIS or other Company system so that an erroneous disconnection does not take place.

d. Please describe whether a Customer Service Representative will have the ability to stop remote disconnection upon receipt of information that would affect the disconnection process such as a medical certificate, and if so, how.

e. Under what circumstances will a Customer Service Representative have the ability to override a pending remote disconnection and prevent a remote disconnection before it takes place?

A-38.

ASSOC. OF COMMUNITY MINISTRIES
EXHIBIT 2

a. The steps outlined in Exhibit DEH-4 pg. 33 will not change. How the disconnect order will be executed is the only new step. The execution of the order, which will continue to be created in the CCS system, will be determined during the design phases of the AMS project. Therefore, Companies are unable to describe the exact process and/or personnel that will be involved in the process.

b. Payments and/or pledges will continue to be posted in the CCS system as they are today. As it works today, if the payment is sufficient to cancel the disconnection order that will occur in the CCS system. How the information will be transferred to the AMS systems will be determined during the design phases of the AMS project.

c. The process of canceling a disconnection order will not change. Cancellations will still occur as they do today in the CCS system. How the information will be transferred to the AMS systems will be determined during the design phases of the AMS project.

d. Customer service representatives will continue to have the ability to stop disconnections. How the information will be transferred to the AMS systems will be determined during the design phases of the AMS project.

e. The policies and practices for a customer service representative to cancel a disconnection order will not change.

Current Disconnection Notice Process

This is an automated process

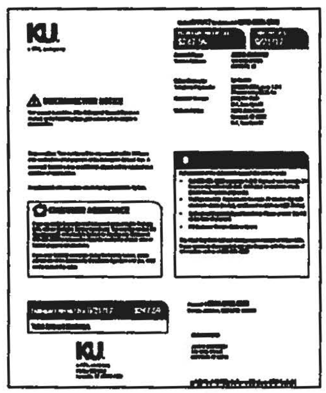
Bill is generated in CIS
Bill is sent to Customer

Bill is generated in Customer Information System based on the customer's billing cycle.

Bill is sent to Customer.

16 business days

If payment is not received within 16 days, a Brown Bill is sent out.



*As soon as the brown bill is received - Best time to reach out to advocacy groups

10 days later

If payment has not been received, create service order to disconnect service for the following business day.

Outcomes

A. If payment or pledge is made before service technician gets to the disconnection location, service order is removed and disconnection is canceled.

B. Service technician disconnects service for non-payment.

C. Service technician does not get to account within 4 day window, service order becomes stale and is removed from work queue and cycle begins again the following month

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to the Association of Community Ministries, Inc.'s First Request for Information
Dated April 2, 2018

Case No. 2018-00005

Question No. 32

Witness: John P. Malloy

Q-32.

a. Please provide complete copies of any LG&E policies relating to disconnection of service for customers who are on the Companies' Medical Alert Program or who have notified LG&E of a medical necessity for service, such as a respirator, and which are not included in response to Question 25 above. If any policies are contained in LG&E's tariffs, please provide copies of the relevant sheets rather than the entire tariff.

b. Please describe in detail LG&E's current procedures for disconnections of service for customers who are on the Companies' Medical Alert Program or who have notified LG&E of a medical necessity, including what steps are carried out by personnel or contractors and what steps are automated. Please include how LG&E ensures that customers are not disconnected in violation of its policies or procedures.

c. Provide copies of any LG&E operating procedures, instructions and training materials for company personnel or contractors who are involved in any way in these procedures.

d. Please describe how each of the procedures described in response to this question will change as a result of LG&E's implementation of remote disconnection of service. Please specify any procedural changes that are anticipated but have not been developed. If new operating procedures, instructions or training materials have been developed, please provide copies.

A-32.

a. All policies related to Medical Alert Program (MAP) are contained in the response to Question No. 25 above.

b. MAP customers are subject to normal dunning procedures, in compliance with our policies and procedures. However, MAP customer accounts are monitored by Company's Revenue Collection department, and a MAP dunning lock is placed on the MAP customer account preventing issuance of a disconnection order. If a threshold past due amount of $500 is reached on the customer's account, Revenue Collection receives an automatic alert for review of the account. If it is determined that collection procedures need to be pursued, the MAP customer is sent a certified letter advising the past due amount must be paid, or financial assistance or payment arrangements made, within 30 days of the receipt of the certified letter. If, at the end of 30 days there has

ASSOC. OF COMMUNITY MINISTRIES
EXHIBIT 3

been no such action by the MAP customer, the account is reviewed again by Revenue Collection management and the Company's legal department to determine if a disconnection is warranted. If it is determined a disconnection is warranted, Revenue Collection will manually create a disconnection service order, to be worked by a field service technician. Revenue Collection will attempt to contact the customer via phone, field visit, e-mail, and/or mail at each step of this process. These contacts are recorded in the Company's SAP Customer Care System (CCS).

c. See attached.

d. There are no expected changes to disconnection eligibility requirements.

Medical Alert Program (MAP)

This program is for LG&E/KU/ODP customers on life-sustaining devices (generally this is a **physician-prescribed ventilator, respirator** or **ventricular assist device**).

Customers on the program are kept informed about planned outages and ongoing restoration work to prevent a life-threatening situation.

"Medical Alert" displays in the alert section if customer is on MAP.

NOTE: Once a year, the customer will have to provide updated proof that they still qualify. Revenue Collection will notify them by letter.

If a customer asks about going on the program,

1. Advise the customer:
    - **The customer must provide proof that they qualify. They will be mailed an application to fill out and return. We will then contact their physician for verification of the medical equipment.**
    - **This is not a guarantee of service.** Outages due to storms, wildlife, fallen trees or other events outside our control can happen at any time and this program is in no way a substitute for having adequate backup service.
    - **Customer can still be disconnected for non-payment.**
2. Enter an Ad Hoc request for form **01059 MAP Application BPEM** which creates a ZMAP semi-automated Contact. When you create and save the Contact, it will automatically create a ZC02 BPEM (business process exception manager) case in CCS, which is forwarded to Revenue Collection.

Additional Information:

- We do not make final decisions regarding program qualification. The MAP process provides three opportunities (in writing) for others to bear the burden of confirmation – not the Company.
- Operations Managers and Office Managers are emailed each time a service order is created to add or remove the customer to/from MAP.

MAP Process - Revenue Collection

For general information about MAP, how to respond to customer inquiries and enter customer's request as a BPEM, see Medical Alert Program.

These steps are used by Revenue Collection after the request has been entered as a BPEM case.

Process

<u>When Revenue Collection Receives</u> ZC02 BPEM Case (request for MAP):

1. Open the BPEM Case and select the Notes tab to review the information. Check to see if there are any special instructions such as a different mailing address.
2. Confirm the account and create a Manual Contact (Class ZMAP and Action 0009 Map-Application requested). Enter a note stating the application is being mailed and include specific notes as needed.
3. To mail the application information to the customer, click the **Adhoc Correspondence** tab on the navigation bar.
4. Select the **Ad Hoc Form of 00701 MAP - Application** from the Ad Hoc Forms drop-down. To see instructions for requesting a form, see Ad Hoc Correspondence and MAP Ad Hoc Forms.
5. Enter the account number into the **Contract Acct** field.
6. The available Form Type selections will show only Print Immediately, Print Batch and View Documents. Select how you would like to send the form and click **Submit**.
7. Reset the due date of the BPEM case to 15 calendar days from the processing date to remind yourself to follow-up on the correspondence if necessary. Click **Save**.
8. Complete the semi-automated contact and click **Save**.

When the completed application is returned, skip to the steps below for **When Completed Application is Received**.

If the application is not received in 15 days, send a second Ad Hoc letter (00101 2nd Letter), stating the application has not been received and that the applicant will be removed from consideration within 10 days. If no response is received to the 2nd letter, enter a Manual Contact explaining why the customer was dropped from the application process.

Once the application has been received, the customer's physician is sent a form letter requesting confirmation of the medical equipment in use. If the form letter is not returned within 15 days, a follow-up letter is sent which gives them 10 days to respond.

Note: It can take up to two months or more from the time the BPEM is created until completion.

<u>When Completed Application is Received:</u>

1. Revenue Collection requests Ad Hoc form 00114 MAP Physician Letter to be sent to the applicant's physician, requesting verification of the medical equipment in use.
2. When the doctor returns the form letter:
    - If the equipment noted on the application is one of the **3 qualifying types**, follow the steps below to add the customer to MAP.
    - If the equipment is NOT one of the qualifying types, the physician letter is reviewed by Occupational Physician Services (2015) for MAP qualification.
        - If our physician approves the application, follow the steps below to add the customer to MAP.
        - If our physician denies the application, based on the equipment in use, send Ad Hoc form 00104 Denial of Application to the customer via certified mail, requesting confirmation of receipt. Revenue Collection

enters a manual Contact on the applicant's account, explaining the reason for denial.

3. If the applicant's doctor fails to return the form letter within 15 days:

    - Send a follow-up letter (Ad Hoc form 00102-no response from doctor) to the applicant, stating we have not received verification from the physician and they will be removed from consideration for the program,if they do not reply in 10 days.
    - If no response is received in the allotted time, the account is removed from consideration. Place a Manual Contact on the CA.

4. If a customer's application has been denied multiple times, Revenue Collection will request Ad Hoc form 00105 Multiple Appln Denial to be sent to the applicant.

Add Customer to MAP (or remove a customer from MAP):

1. After the application is approved, verify that we have an outage number for the customer.
2. To add the **MAP Enrollment Date** (the date the orders are placed) click the **BP Overview** tab on the navigation bar. Click **Edit** and select the date from the calendar in the Map Enrollment field. (To remove customer from MAP, delete the MAP Enrollment Date). Click **Save**.
3. Complete the semi-automatic contact to explain the Enrollment Date change.
4. Change the Dunning Procedure on the account to **MAP Accounts**.
5. Access the Installation and change the Deregul. Status to M. This will put a special condition (Medical Alert) on the account and alert ARM (electric distribution operations) personnel to the MAP priority. (If removing customer from MAP, change this back to blank).
    - Enter T-code **es31**.
    - From the Change Installation screen, enter the Installation number in the Installation field.
    - Change the Deregul Status in the Deregulation section to "M-Medical Alert." This will create and Alert on the account that states Medical Alert Program. Click **Save**.
    - Create a Manual Contact explaining the Installation change.
6. Create a ZIMD (put medical alert on meter and transformer) service order for the NEXT business day to add the medical alert meter seals and transformer tags. This ensures our field personnel are aware the customer is enrolled in MAP.

   NOTE: To remove customer from MAP, select Order Type ZRMD Remove Medical Alert
7. Revenue Collection updates the spreadsheet information on SharePoint. The Medical Alert Program Customer List is located on the Grid under the Asset Information Team Site. This information is available to all Operation managers, Business Office managers and other pertinent personnel.

8. Operation managers and Business Office managers are e-mailed each time a service order is created to add or remove a customer from MAP.

Annual MAP Recertification:

MAP customers must be re-certified every year to demonstrate that they are still eligible for MAP.

1. Once a year, a ZC01 Recertify MAP App Process BPEM case is routed to Revenue Collection for each MAP customer to start the recertification process. The case is triggered by the MAP Enrollment Date which is the manually entered date that the customer was enrolled into the program.
2. Revenue Collection then notifies the customer by letter (Ad Hoc form Recertify MAP 00106) to provide a new application so we can write to their physician to re-confirm they still use eligible equipment. The equipment types which qualify are: Respirator, Ventilator or a Ventricular Assist Device. The customer goes through the same process as they did in the beginning when they applied for the program.
3. If the customer does not respond by returning the completed application (by them) then Revenue Collection will request Ad Hoc 00103 2nd Recertify MAP explaining to the customer they have 10 days to return the application to us or we will determine they no longer need the program. If no response within the 10 days the customer is evaluated for removal. If the decision is made to remove the customer, the special alert is removed from the account and a ZRMD Remove Medical Alert order is placed to remove the tag and seal from that location.
4. If a MAP customer is removed due to no longer qualifying due to the physician verification, Revenue Collection will request Ad Hoc form 0010 Denial of Application which explains that acceptance will only be granted again if circumstances change and we receive confirmation from the applicant's physician.
5. Revenue Collection will then create a ZRMD Remove Medical Alert service order to remove the MAP tags from the meter and transformer.

Dunning of MAP Customer

See Dunning Levels - Active Accounts

1. When a MAP customer reaches Active Dunning Level 3, a ZF22 BPEM case is automatically created and sent to Revenue Collection.
2. If the account balance exceeds $500, the person working the BPEM notifies Revenue Collection Management and the appropriate Business Office to review the situation and decide whether or not we should pursue collection.
3. If the managers advise Revenue Collection we need to pursue collection, then the office sends a certified letter to the customer giving them 30 days to obtain financial assistance or to make payment arrangements.

Certified Letter Example

Month Day, Year

[recipient's address]

Dear Sir or Madam:

We have not received a payment on your account since xx/xx/xxxx. Your account is now past due in the amount of $xxx.xx. We have sent multiple notification(s) of past due balance(s) on your Kentucky Utilities account. It is imperative that you contact our office immediately to avoid any further collection actions. If we do not receive a response from you within thirty (30) days, further collection action will be taken up to and including disconnection of service. To avoid disconnection of service, payment must be made in full by xx/xx/xxxx.

The Medical Alert Program designation on your account simply means that Kentucky Utilities will make reasonable efforts to restore service to your address on a priority basis in the event of an outage. It in no way excludes you from the responsibility of paying your bills in a timely fashion.

Please consider this your last notice prior to disconnection of service on or after xx/xx/xxxx. If payment cannot be made by xx/xx/xxxx, please make arrangements to relocate the person living in your home who relies on life support equipment before that date. In addition to this certified letter a duplicate letter will be hand delivered to your residence.

Please contact Kentucky Utilities Company for payment arrangements or agency information. If you have any questions or concerns, please contact us.

Sincerely,

Revenue Collection Department

MAP Administration

859-367-5303

5. At the end of the 30 days, the Business Office Manager and Revenue Collection notify the Legal Department of the situation and they all decide together whether to create a disconnect order. If so, they advise the person working the BPEM case to enter a manual Disconnect Order.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR FULL DEPLOYMENT OF ADVANCED METERING SYSTEMS	)	**CASE NO. 2018-00005**

VERIFIED INFORMATIONAL UPDATE FILING

This Verified Informational Update Filing of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies") provides updates to cost-benefit information included in various locations in the record. The 2017 Tax Cuts and Job Act ("Tax Act") will affect revenues the Companies collect, at least in the short run, due to reduced corporate tax rates being reflected in utility rates.[1] As a result, two categories of benefits that the Companies calculated based on revenues (non-technical losses and ePortal) could decrease relative to the benefits presented in the Companies' application, though it is also possible that other factors affecting rates could reduce or offset entirely the effects of the Tax Act on rates. Nonetheless, in the interest of providing the Commission full and complete information, the Companies present below an updated table in the same format the Companies provided in their January 30 filing. The table assumes revenues will relatively decrease due to the Tax Act across the entire cost-benefit study period, which results in reduced non-technical losses and ePortal benefits:[2]

[1] Tax Cuts and Jobs Act, H.R. 1, Public Law 115-97, 131 Stat. 2054 (Dec. 22, 2017).
[2] The explanations of the discount rates and other matters pertaining to the table filed in the January 30 filing also apply to the table below.

ATTORNEY GENERAL
EXHIBIT 1

AMS Cost-Benefit Summary (2018-2040)				
$M	Nominal Cash Outlays or Benefits[1]	Revised Nominal RR	NPVRR As Filed[1]	NPVRR Revised for Tax Act
(Costs)				
Total Project Costs (Capital)	(320.0)	(515.0)	(357.1)	(342.5)
Total Project Costs (O&M)	(29.8)	(29.8)	(26.0)	(25.8)
Total Project Costs	$ (349.8)	$ (544.8)	$ (383.1)	$ (368.3)
Total Recurring Costs (Capital)	(43.8)	(63.0)	(22.3)	(20.9)
Total Recurring Costs (O&M)	(108.8)	(108.8)	(47.9)	(46.5)
Total Recurring Costs	$ (152.6)	$ (171.8)	$ (70.2)	$ (67.4)
Total Lifecycle Costs	$ (502.4)	$ (716.6)	$ (453.3)	$ (435.7)
Benefits				
Operational Savings	425.1	425.1	208.3	203.1
ePortal Benefit	158.0	155.3	76.7	73.5
Recovery of Non-Technical Losses	402.3	385.1	196.8	183.7
Total Lifecycle Benefits	$ 985.4	$ 965.5	$ 481.8	$ 460.3
Net Benefits vs (Costs)	$ 483.0	$ 248.9	$ 28.5	$ 24.6
Discount Rate			6.32%	6.58%

[1] As presented in the January 30, 2018 Verified Informational Update Filing.

The table below similarly updates the values presented on page 23 of the Rebuttal Testimony of John P. Malloy:

	Service Life		
$M	15-year	18-year	20-year
Project NPVRR*	$ 67.2	$ 18.1	$ (11.6)
Nominal Benefit	$ 648.0	$ 803.6	$ 913.8
Benefit NPV	$ 368.4	$ 417.6	$ 447.3

*Negative amount means benefits exceed costs

Again, it is possible that other factors will reduce or offset entirely the effects of the Tax Act on future revenues. That notwithstanding, the Companies are providing this informational update to ensure the Commission has ample information to evaluate this application.

Dated: July 3, 2018

Respectfully submitted,

Kendrick R. Riggs
W. Duncan Crosby III
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
Telephone: (502) 333-6000
Facsimile: (502) 627-8722
kendrick.riggs@skofirm.com
duncan.crosby@skofirm.com

Allyson K. Sturgeon
Managing Senior Counsel
Regulatory and Transactions
Sara V. Judd
Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202
Telephone: (502) 627-2088
Facsimile: (502) 627-3367
allyson.sturgeon@lge-ku.com
sara.judd@lge-ku.com

Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John P. Malloy**, being duly sworn, deposes and says he is the Vice President, Gas Distribution for Louisville Gas and Electric Company, and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the Verified Informational Update Filing, and the content thereof is true and correct to the best of his information, knowledge, and belief.

JOHN P. MALLOY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of July 2018.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

CERTIFICATE OF COMPLIANCE

In accordance with 807 KAR 5:001 Section 8(7), this is to certify that Louisville Gas and Electric Company and Kentucky Utilities Company's July 3, 2018 electronic filing of its *Verified Informational Update Filing* is a true and accurate copy of the documents being filed in paper medium; that the electronic filing was transmitted to the Commission on July 3, 2018; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that an original and six copies of the filing will be mailed by first class U.S. Mail, postage prepaid, to the Commission on July 3, 2018.

Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	CASE NO. 2016-00370

DIRECT TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

KENTUCKY UTILITIES COMPANY

Filed: November 23, 2016

ATTORNEY GENERAL
EXHIBIT 2

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. CAN YOU BRIEFLY DESCRIBE GANNETT FLEMING?

A. Yes. Gannett Fleming, Inc. is an international engineering consulting firm with expertise in numerous disciplines. Founded in 1915, Gannett Fleming Inc. has a long history of consulting services. The firm's headquarters is located in suburban Harrisburg, Pennsylvania. Regional offices are maintained in 22 states, two Canadian provinces, and an office in Abu Dhabi, United Arab Emirates. With 2,000 highly qualified individuals across a global network of 60 offices, we help shape infrastructure and improve communities in more than 65 countries. Gannett Fleming Valuation and Rate Consultants, LLC and its predecessor, the Valuation and Rate Division of Gannett Fleming, Inc., have provided service to utility companies since the late 1930s and, in the last five years alone, have prepared over 100 depreciation and valuation studies. The Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming) staff has an unparalleled depth and breadth of experience in the field of depreciation. This expertise has been gained not only by conducting depreciation studies but also by actively participating within the depreciation field as educators and members of organizations that form depreciation standards.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since college graduation in June, 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am Senior Vice President.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member and past President of the Society of Depreciation Professionals. I am also a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, and January 2013.

Q. HAVE YOU HAD ANY ADDITIONAL EDUCATION RELATING TO UTILITY PLANT DEPRECIATION?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and

"Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. Yes. I have 30 years of depreciation experience which includes giving expert testimony in over 230 cases before 40 regulatory commissions, including this Commission. Please refer to Exhibit JJS-1 for my qualifications. In addition to the cases that I have submitted testimony, I have supervised in over 400 other depreciation or valuation projects.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I sponsor the depreciation study that Gannett Fleming performed for Kentucky Utilities Company attached hereto as Exhibit JJS-KU-1.

II. <u>DEPRECIATION STUDY</u>

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which can be reasonably anticipated or contemplated, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. DID YOU PREPARE THE DEPRECIATION STUDY FILED BY KENTUCKY UTILITIES COMPANY IN THIS PROCEEDING?

A. Yes. I prepared the depreciation study submitted by Kentucky Utilities Company with its filing in this proceeding. This study is attached as Exhibit JJS-KU-1. My report is entitled: "2015 Depreciation Study - Calculated Annual Depreciation Accruals Related to

Electric Plant as of December 31, 2015." This report sets forth the results of my depreciation study for Kentucky Utilities Company.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH PAST PRACTICES?

A. The methods and procedures of this study are the same as those utilized in past studies of this Company as well as others before this Commission. The depreciation rates recommended in my study are determined based on the average service life procedure and the remaining life method.

Q. ARE THE UNDERLYING LIFE AND SALVAGE PARAMETERS AND RESULTING DEPRECIATION ISSUES IN THIS STUDY CONSISTENT WITH INDUSTRY TRENDS?

A. Yes. The life and salvage parameters for KU has changed consistently with others in the industry as well as the major changes to steam production asset mix.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. The Depreciation Study is presented in nine parts; Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

Table 1 on pages VI-4 through VI-9 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2015, the book depreciation reserve and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2015.

Q. **PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.**

A. I used the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

For General Plant Accounts 391.1, 391.2, 391.31, 393, 394, 397.1 and 397.2 in electric plant, I used the straight line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of December 31, 2015. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. WILL YOU PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP?

A. The service life and net salvage study consisted of compiling historical data from records related to Kentucky Utilities Company's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans related to plant operations; and interpreting the data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1900 through 2015. The transactions included additions, retirements, transfers, sales and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE KENTUCKY UTILITIES' SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. A survivor curve is a graphical depiction of the amount of property existing at each age throughout the life of an asset class. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa curve system to which the property group belongs, and the relative height of the mode. For example, the Iowa 50-R1.5 indicates an average service life of fifty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT FACILITIES STRUCTURES SUCH AS PRODUCTION PLANTS?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as, for a building, the retirements of plumbing, heating, doors, windows, roofs, etc., that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. HAS GANNETT FLEMING USED THIS APPROACH IN OTHER PROCEEDINGS?

A. Yes, we have used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada, including Kentucky. This technique is currently being utilized by Kentucky Utilities Company in the same manner recommended in this case.

Q. WHAT ARE THE BASES FOR THE PROBABLE RETIREMENT YEARS THAT YOU HAVE ESTIMATED FOR EACH FACILITY?

A. The bases for the probable retirement years are life spans for each facility that are based on informed judgment, and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirements of these facilities are not yet subject to specific management plans. Such plans would be premature. At the appropriate time, studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the facility's life span.

Q. DID YOU PHYSICALLY OBSERVE KENTUCKY UTILITIES COMPANY'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made a field review of Kentucky Utilities Company's property as part of this study during October 2015 and previously reviewed assets in April 2007 and October 2011 to observe representative portions of plant. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1988 through 2015 and considered estimates for other electric companies.

Q. HAVE YOU INCLUDED A DISMANTLEMENT COMPONENT INTO THE OVERALL RECOVERY OF GENERATING FACILITIES?

A. Yes. A dismantlement component has been included to the net salvage percentage for steam, hydro and other production facilities.

Q. CAN YOU EXPLAIN HOW THE DISMANTLEMENT COMPONENT IS INCLUDED IN THE DEPRECIATION STUDY?

A. Yes. The dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of KU, it was determined that the dismantlement or decommissioning costs for steam production facilities is best calculated at $40/KW of the assets subject to final retirement. The percentage for dismantlement of hydro and other production facilities is $10/KW of the assets surviving at final retirement with the exception of the combined facility which is

$20/KW. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. The detailed calculation for each location is set forth on pages VIII-2 and VIII-3 of Exhibit JJS-KU-1.

Q. IS THIS METHODOLOGY A CHANGE FROM CURRENT PRACTICES?

A. No. The current practice for KU includes a low level of terminal net salvage combined with the interim net salvage percentage. In this study, the methodology continues to advance to a more precise practice and is utilized by most utilities. The weighting of the interim and final net salvage by location establishes a more precise recovery pattern for each location.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. Amortization accounting is used for accounts with a large number of units, but small asset values. Therefore, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life during which the asset will render full benefit. For example, in amortization accounting, assets that have a 25-year amortization period will be fully recovered after 25 years of service and taken off the Company's books, but not necessarily removed from service. In contrast, assets that are taken out of service before 25 years remain on the books until the amortization period for that vintage has expired.

Q. AMORTIZATION ACCOUNTING IS BEING UTILIZED FOR WHICH PLANT ACCOUNTS?

A. Amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.1, 391.2, 391.31, 393, 394, 395, 397.1 and 397.2 for electric plant which represents slightly less than one percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 368, Line Transformers, as an example because it is one of the largest depreciable mass accounts and represents approximately 4% of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1900 through 2015 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1900-2015 and 1961-2015 experience bands are presented on pages VII-156 through VII-161 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-156 shows $1,000,314 retired at age 0.5 with $358,997,061 exposed to retirement. Consequently, the retirement ratio is 0.0028 and the surviving ratio is 0.9972. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 46-R2 on page VII-155.

The net salvage analyses for Account 368, Line Transformers, is presented on pages VIII-58 and VIII-59 of the Depreciation Study. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1985 through 2015. This 31-year period experienced $2,723,059 ($6,364,201 - $9,087,260) in negative net salvage for $41,778,150 plant retired. The result is negative net salvage of 7 percent ($2,723,059/$41,778,150). Based on the overall negative 7 percent net salvage and the most recent five years of positive 5 percent, as well as industry ranges and Company expectations, it was determined that negative 5 percent is the most appropriate estimate.

My calculation of the annual depreciation related to the original cost at December 31, 2015, of utility plant is presented on pages IX-126 and IX-127. The calculation is based on the 46-R2 survivor curve, 5% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-9.

Q. WERE THERE ANY SPECIFIC ACCOUNT CHANGES TO DEPRECIATION METHODS PROPOSED IN THE DEPRECIATION STUDY?

A. Yes. The depreciation calculations for Account 370.0, Meters, and Account 370.1, Metering Equipment, including the anticipated Advanced Metering System (AMS) program of new technology meters. First, the life characteristics of these two subaccounts include historical data through 2015 and projected data through 2021. This combined life analyses properly estimates the full life cycle of the current meters and metering equipment. Second, the application of the full life characteristics of the two accounts are used to determine the annual depreciation accrual rate in the study. This calculation is performed in the segregated book reserve in order to avoid unnecessarily high depreciation expense due to the accelerated replacement or conversion of the meters. According to Mr. Garrett's testimony, the regulatory asset which represents the remaining reserve amount will be established at the end of the program and recovered in a future period. The segregation does not change the past recovery or the total amount to be recovered, however, it does create a more systematic and natural recovery that will not affect future meter assets.

Q. WAS THERE ALSO A NEW ASSET CLASS ADDED TO METERS SINCE THE LAST DEPRECIATION STUDY?

A. Yes. Account 370.20, Meters – AMS, represent the new technology meters which were first placed into service in 2015. These meters are expected to have a shorter average life and maximum life than the standard meters they are replacing. The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential of 25 years. The 15-S2.5 survivor curve best fits this life characteristic.

Q. **WHAT IS THE EFFECT OF THESE CHANGES ON DEPRECIATION?**

A. The annual depreciation rates and annual depreciation expense for meters has increased as of December 31, 2015.

Q. **DOES THE INCREASED DEPRECIATION EXPENSE FOR METERS AFFECT ELECTRIC PLANT?**

A. Yes, although the distribution plant function in Electric Plant has decreased, the changes in depreciation practices for Accounts 370.0 and 370.1 as well as the addition for Account 370.2, cause the overall decrease to be smaller.

III. <u>CONCLUSION</u>

Q. **IN YOUR OPINION, ARE THE DEPRECIATION RATES SET FORTH IN EXHIBIT JJS-KU-1 THE RECOMMENDED RATES FOR THE KENTUCKY PUBLIC SERVICE COMMISSION TO ADOPT IN THIS PROCEEDING FOR KU?**

A. Yes, these rates appropriately reflect the rates at which the value of KU's assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric rates in this matter and for the Company to use for booking depreciation and amortization expense going forward.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA	)	
	)	**SS:**
COUNTY OF CUMBERLAND	)	

The undersigned, **John J. Spanos**, being duly sworn, deposes and says he is Senior Vice President, for Gannett Fleming Valuation and Rate Consultants, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos

John J. Spanos

Subscribed and sworn to before me, a Notary Public in and before said County and Commonwealth, this 8th day of November 2016.

(SEAL)

Notary Public

My Commission Expires:

February 20, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to the Attorney General's Supplemental Data Request for Information
Dated April 27, 2018

Case No. 2018-00005

Question No. 5

Witness: John P. Malloy

Q-5. Reference the "AMS Cost-Benefit Summary (2018-2040)", Malloy testimony page 15. Recalculate the Net Present Value column of this table using all projected Nominal Values in the current business case using a 15-year and 18-year benefit period rather than a 23-year benefit period. Retain all current assumptions (such as discount rate) in your response as were used to develop the original figures in the Summary on Malloy testimony page 15.

A-5.

15-year AMS Cost-Benefit Summary (2018-2032)

$M	Nominal Values	Net Present Values
(Costs)		
Total Project Costs (Capital)	(320.0)	(357.1)
Total Project Costs (O&M)	(29.8)	(26.0)
Total Project Costs	$ (349.8)	$ (383.1)
Total Recurring Costs (Capital)	(26.2)	(15.8)
Total Recurring Costs (O&M)	(54.1)	(30.3)
Total Recurring Costs	$ (80.3)	$ (46.1)
Total Lifecycle Costs	$ (430.1)	$ (429.2)
Benefits		
Operational Savings	237.8	147.8
ePortal Benefit	89.0	54.4
Recovery of Non-Technical Losses	228.1	140.6
Total Lifecycle Benefits	$ 554.9	$ 342.8
Net Benefits vs (Costs)	$ 124.8	$ (86.4)

Discount Rate: 6.32%

ATTORNEY GENERAL
EXHIBIT 3

18-year AMS Cost-Benefit Summary (2018-2035)

$M		Nominal Values		Net Present Values
(Costs)				
Total Project Costs (Capital)		(320.0)		(357.1)
Total Project Costs (O&M)		(29.8)		(26.0)
Total Project Costs	**$**	**(349.8)**	**$**	**(383.1)**
Total Recurring Costs (Capital)		(29.2)		(17.2)
Total Recurring Costs (O&M)		(73.3)		(37.5)
Total Recurring Costs	**$**	**(102.5)**	**$**	**(54.7)**
Total Lifecycle Costs	**$**	**(452.3)**	**$**	**(437.8)**
Benefits				
Operational Savings		304.3		172.8
ePortal Benefit		113.6		63.6
Recovery of Non-Technical Losses		290.2		163.9
Total Lifecycle Benefits	**$**	**708.1**	**$**	**400.3**
Net Benefits vs (Costs)	**$**	**255.8**	**$**	**(37.5)**

Discount Rate: 6.32%

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to Commission Staff's First Request for Information
Dated April 2, 2018

Case No. 2018-00005

Question No. 9

Witness: John P. Malloy

Q-9. Refer to the Direct Testimony of John P. Malloy ("Malloy Testimony"), page

a. Provide any data relied upon by the Companies which would support an expected 20-year lifespan.

b. Explain any rate implications if the Commission were to ultimately approve a shorter service life for the AMS meters and gas indices.

A-9.

a. Based on experience and discussions with the planned meter vendor, Landis + Gyr, the Companies expect meters and indices deployed during the program to last 20 years on average. See attached.

In addition to the vendor information, the Companies relied upon information from other utilities that have assumed 20-year service lives for AMS meters. See Malloy Testimony, page 21, line 18 to page 24, line 10.

b. All other things being equal, shorter service lives tend to increase depreciation expense, which in turn tend to increase rates, at least in the short run. If depreciable lives are initially set shorter than actual service lives, depreciation expense will likely be too high in the early years and too low in later years.

ATTORNEY GENERAL
EXHIBIT 4

From: Hilton, Tim
To: Whitehouse, Jonathan
Cc: Brennan, Paul
Subject: Re: Meter life
Date: Wednesday, March 16, 2016 8:40:31 AM

---

20 years.

Sent from my iPad

On Mar 16, 2016, at 8:20 AM, Whitehouse, Jonathan <[redacted]> wrote:

Paul/Tim,

What is the expected life of the RF Focus AXe meters? Thanks.

Jonathan Whitehouse | Advanced Metering Systems Engineer
LG&E and KU Energy LLC | [redacted] | [redacted]
[redacted] | www.lge-ku.com

LG&E KU
PPL companies

RECEIVED
JUN 30 2014
PUBLIC SERVICE
COMMISSION

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

LG&E and KU Energy LLC
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Rick E. Lovekamp
Manager - Regulatory Affairs
T 502-627-3780
F 502-627-3213
rick.lovekamp@lge-ku.com

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.

ATTORNEY GENERAL
EXHIBIT 5

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

Rick E. Lovekamp

c: Parties of Record

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

Mark A. Martin
Vice President, Rates and Regulatory Affairs
Atmos Energy Corporation
3275 Highland Pointe Drive
Owensboro, KY 42303
mark.martin@atmosenergy.com

(270) 685-8024

James M. Miller
Tyson Kamuf
SULLIVAN, MOUNTJOY, STAINBACK &
MILLER, P.S.C.
100 St. Ann Street
P. O. Box 727
Owensboro, Kentucky 42302-0727
Phone: (270) 926-4000
Facsimile: (270) 683-6694
jmiller@smsmlaw.com
tkamuf@smsmlaw.com

Counsel for Big Rivers Electric Corporation and its member distribution cooperatives: Jackson Purchase Energy Corporation, Kenergy Corp. and Meade County Rural Electric Cooperative Corporation

Albert A. Burchett
Albert A. Burchett, Attorney at Law
P.O. Box 346
Prestonsburg, KY 41653
Telephone: (606) 874-9701

Counsel for Big Sandy RECC

Ralph Combs
100 United Drive, Suite 4B
Versailles, KY 40383
Telephone: (859) 873-5427
Fax: (859) 873-1024
e-mail: rcombs@hbkylaw.com

Counsel for Blue Grass Energy Cooperative Corporation

John S. Pumphrey
Grant, Rose & Pumphrey
51 South Main Street
Winchester, KY 40391
Telephone: (859) 744-6828

Counsel for Clark Energy Cooperative, Inc.

Stephen B. Seiple
Stephen B. Seiple
200 Civic Center Drive
P.O. Box 117
Columbus, OH 43216-0117
Telephone: (614) 460-4648
Fax: (614) 460-6986
Email: sseiple@nisource.com

Richard S. Taylor
225 Capital Avenue
Frankfort, KY 40601
Telephone: (502) 223-8967
Fax: (502) 226-6383
Email: attysmitty@aol.com

Counsel for Columbia Gas of Kentucky, Inc.

W. Patrick Hauser
W. Patrick Hauser, P.S.C.
200 Knox Street
P.O. Box 1900
Barbourville, KY 40906
Telephone: (606) 546-3811
phauser@barbourville.com

Counsel for Cumberland Valley Electric, Inc.

Robert M. Watt III
Stoll Keenon Ogden PLLC
300 W. Vine Street, Suite 2100
Lexington, KY 40507-1801
Telephone: 859-231-3000
Fax: 859-246-3643
robert.watt@skofirm.com

Counsel for Delta Natural Gas Company, Inc.

Rocco D'Ascenzo
Associate General Counsel
Duke Energy Kentucky, Inc.
139 East Fourth Street/ 1303 Main
P. O. Box 960
Cincinnati, OH 45202

David S. Samford
Goss Samford, PLLC
2365 Harrodsburg Road
Suite B325
Lexington, KY 40504

Counsel for Duke Energy Kentucky, Inc.

Mark David Goss
Goss Samford, PLLC
2365 Harrodsburg Road
Suite B325
Lexington, KY 40504
Telephone: (859) 368-7740
mdgoss@gosssamfordlaw.com

Counsel for East Kentucky Power Cooperative, Inc. and South Kentucky Rural Electric Cooperative Corporation

Woodford L. Gardner, Jr.
Richardson Gardner & Alexander
117 East Washington Street
Glasgow, KY 42141
270-651-8884 office
270-651-5662 facsimile
wlg@rgba-law.com electronic mail
Counsel for Farmers Rural Electric
Cooperative Corporation

Marvin W. Suit
Suit, Price, Price & Ruark, PLLC
207 Court Square
Flemingsburg, KY 41041
Telephone: (606) 849-2338
msuit2@windstream.net

Counsel for Fleming-Mason Energy Cooperative, Inc.

J. Hadden Dean
Sheehan, Barnett, Dean, Pennington, Little & Dexter, PSC
116 North Third Street
P.O. Box 1517
Danville, KY 40423-1517
Telephone: (859) 236-2641
Facsimile: (859) 236-0081

Counsel for Inter-County Energy Cooperative Corporation

Clayton O. Oswald
Taylor, Keller & Oswald, PLLC
1306 W. 5th Street, Suite 100
P.O. Box 3440
London, KY 40743-3440

Phone: (606) 878-8844
FAX: (606) 878-8850
E-mail: csoswald@tkolegal.com

Counsel for Jackson Energy Cooperative

R. Benjamin Crittenden
Stites & Harbison PLLC
421 W. Main Street
P.O. Box 634
Frankfort, KY 40602-0634
Telephone: 502-223-3477
Facsimile: 502-223-4124
email: rcrittenden@stites.com

Counsel for Kentucky Power Company

Gregory D. Allen
Greg D. Allen Law Office
P. O. Box 585
Salyersville, KY 41465-0585
Telephone: (606) 349-8000

Counsel for Licking Valley Rural Electric Cooperative Corporation

Respectfully submitted,

By: ______________________

W. Duncan Crosby III
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, KY 40202
Telephone: (502) 333-6000
duncan.crosby@skofirm.com

– and –

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088
allyson.sturgeon@lge-ku.com

Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

John J. Scott
John J. Scott, PSC
108 East Poplar Street
P.O. Box 389
Elizabethtown, KY 42702-0389
Telephone: (270) 765-2179
john@johnscottlaw.org

Counsel for Nolin Rural Electric Cooperative Corporation

James M. Crawford
Crawford & Baxter, P.S.C.
523 Highland Avenue
P.O. Box 353
Carrollton, Kentucky 41008
Phone: (502) 732-6688
Fax: (502) 732-6920
E-mail: CBJ523@aol.com

Counsel for Owen Electric Cooperative, Inc.

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.

John Douglas Hubbard

John Douglas Hubbard
Fulton Hubbard & Hubbard
117 East Stephen Foster Avenue
Bardstown, KY 40004
Telephone: (502) 348-6457
Facsimile: (502) 348-8748
Email: jdh@bardstown.com

Counsel for Salt River Electric Cooperative Corporation

Donald T. Prather
Mathis, Riggs and Prather, PSC
500 Main Street, Suite 5
Shelbyville, KY 40065
Telephone: (502) 633-5220

Counsel for Shelby Energy Cooperative, Inc.

Robert Spragens, Jr.
Spragens & Higdon, P.S.C.
P.O. Box 681
Lebanon, KY 40033
Telephone: (270) 692-3141
Facsimile: (270) 692-6693
rspragens@spragenshigdonlaw.com

Counsel for Taylor County Rural Electric Cooperative Corporation

Iris G. Skidmore
Bates & Skidmore
415 W. Main Street, Suite 2
Frankfort, KY 40601

Counsel for Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc.

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

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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

[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.

- o <u>AG</u>: 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.

- o <u>CAC</u>: 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**

  - o <u>Joint Utilities</u>: 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.

  - o <u>AG</u>: Both technical and informational opt-out should be available to customers, where infrastructure allows.

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

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- **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.

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- 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.

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- **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.

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- 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.

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[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.

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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:

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

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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.

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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."

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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

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[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."

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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.

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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 concems 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 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;

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- 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,

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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.

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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.

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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.

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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.

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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.

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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.

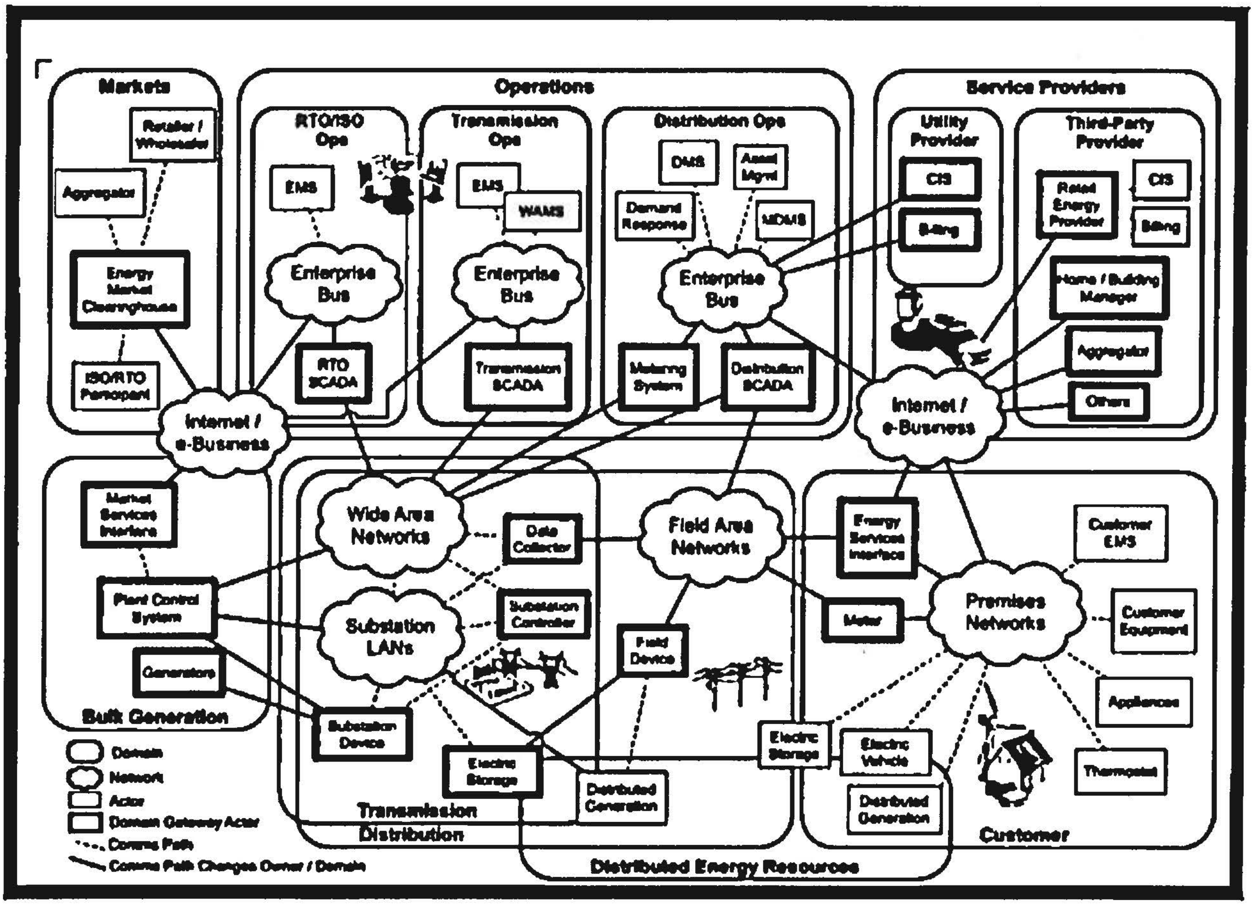
II. Scope of the Distribution Smart-Grid Components Section

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

[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.

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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 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.

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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.

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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.

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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

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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).

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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

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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.

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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

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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.

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[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 of 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).

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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).

EISA 2007 SMART GRID INFORMATION AND INVESTMENT STANDARDS

> 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.

[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 Southern 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

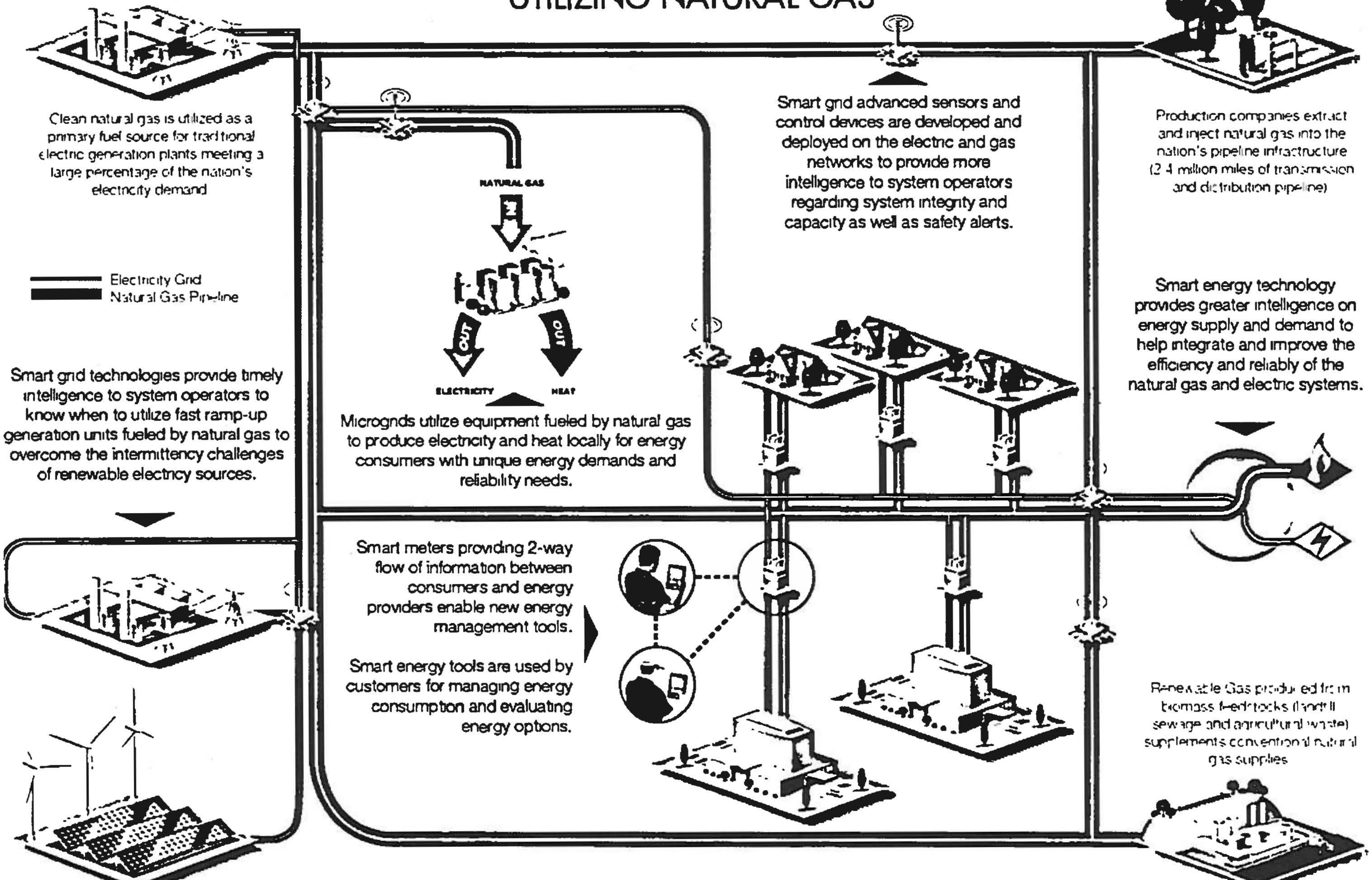
As federal and state policy makers advance a smart energy future, natural gas and natural gas technologies must play a central role.

- 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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APPENDIX D

PPL companies

R... IVED
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PUBLIC S... VICE
COMMISSION

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

LG&E and KU Energy LLC
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Rick E. Lovekamp
Manager – Regulatory Affairs
T 502-627-3780
F 502-627-3213
rick.lovekamp@lge-ku.com

February 27, 2015

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 Brief 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, Grayson Rural Electric Cooperative Corporation, 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. The signature pages for each party are attached to the Joint Brief.

ATTORNEY GENERAL
EXHIBIT 6

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

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

c: Parties of Record

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

BRIEF 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, GRAYSON RURAL ELECTRIC COOPERATIVE CORPORATION, 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

Filed: February 27, 2015

ADMINISTRATIVE CASE NO. 2012-00428
BRIEF OF THE JOINT UTILITIES

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ADMINISTRATIVE CASE NO. 2012-00428
BRIEF OF THE JOINT UTILITIES

I. Introduction

When the Commission began this proceeding on October 1, 2012, it set the ambitious goal of "address[ing] all aspects of a Smart Grid system from hardware and software issues to reliability improvement, cost recovery issues, and dynamic pricing," as well as "consider[ing] the adoption of the EISA 2007 [Energy Independence and Security Act of 2007] Smart Grid Investment Standard and the EISA 2007 Smart Grid Information Standard."[1] Over the course of more than two years of this proceeding, as well as the work and consideration given to the EISA 2007 standards in the predecessor case, Case No. 2008-00408, the Joint Utilities believe the Commission has achieved its goals; all of the topics the Commission sought to be addressed in this proceeding have indeed been addressed.[2] It is a significant accomplishment.

The Joint Utilities believe it is also significant that over the course of this proceeding and Case No. 2008-00408 they have unanimously and consistently expressed to the Commission their view on every topic: The Commission's existing authority is sufficient to address all smart-grid related issues, and no additional regulations or other forms of binding requirements are necessary either to ensure that Kentucky's utilities continue to propose and implement cost-effective smart-technology solutions or to ensure the Commission has adequate oversight of such implementations and their rate and service impacts. Therefore, the Joint Utilities have proposed non-binding conceptual frameworks that utilities and the Commission may consider when proposing, evaluating, or reviewing smart-technology implementations and related topics. As discussed below, it continues to be the Joint Utilities' unanimous view, consistently held for more than five years across two proceedings, that it is unnecessary, and could be

[1] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 1-2 (Oct. 1, 2012).
[2] "Joint Utilities" includes all the parties named as Joint Utilities on the cover page of this brief.

counterproductive, for the Commission to implement in any form either of the EISA 2007 smart-grid standards or any other smart-technology related standard or other binding requirement concerning any of the issues the Commission has addressed in this proceeding. The Joint Utilities therefore respectfully ask the Commission to issue a final order closing this proceeding without imposing any binding regulation, standard, or other requirement related to any of the issues addressed in this proceeding.

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.

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- 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.

- 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.[3]

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.

[3] *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).

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 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.[4]

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 Attorney General ("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

[4] *Id.* at 4.

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.

The Joint Utilities do not oppose the economical use of smart technologies. But the Joint Utilities do oppose mandatory standards that could stifle innovation or otherwise curtail each utility's ability to implement what is most economical and sensible for its customers and service territory; that is why the Joint Utilities oppose the EISA 2007 Smart Grid Investment Standard.

IV. Other Issues Addressed in this Proceeding

On July 17, 2013, the Commission issued an order directing the Joint Utilities, the 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),[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 Smart Grid Investment and Information Standards proposed in EISA 2007.[6] On June 30, 2014, the Joint Utilities submitted to the Commission their report to

[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).

the Commission on these topics ("Joint Report"), which included comments from the AG and CAC.

The Joint Utilities continue to support the views they expressed in the Joint Report, which are summarized below (with the exception of the Joint Utilities' views on the EISA 2007 standards, which are addressed at length above).

A. <u>Customer Privacy</u>

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 proposed in the Joint Report a voluntary, non-binding list of terms to define and substantive items for utilities to consider when reviewing customer-privacy policies and practices, which the Commission may find useful when addressing smart-grid or other customer-privacy-related utility proposals.

B. <u>Opt-Out Provisions</u>

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. Instead, a case-by-case approach using some or all of the non-binding analytical framework presented in the Joint Report may be an appropriate approach to evaluate opt-outs.

C. Customer Education

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 on a voluntary, non-binding basis 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 the Joint Report.

D. Dynamic Pricing

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 the Joint Report (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.

E. Distribution Smart-Grid Components

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.

F. Cyber-Security

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.

G. Cost Recovery

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.

H. How Natural Gas Companies Might Participate in the Electric Smart Grid

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.

V. Conclusion and Recommendations

The Joint Utilities have appreciated the opportunity to explore with the Commission, AG, CAC, and each other the various smart-technology-related topics that have been the focus of this proceeding and its predecessor, Case No. 2008-00408. Much useful information has entered the record of the proceeding, and each of the Joint Utilities has learned from the other participants. Collectively, the Joint Utilities believe they have produced useful guides for the Commission and others to use when considering these topics. In particular, the voluntary, non-binding analytical tools and frameworks provided in the Joint 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. Notably, the Joint Utilities have made additional investments in smart and advanced technologies during the pendency of this proceeding and its predecessor, investments that have been subject to the Commission's existing rate and other review processes; the Joint Utilities believe these reviews have provided adequate opportunities to review such investments for the parties desiring to seek such review and approval. 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.

Mark A. Martin
Vice President, Rates and Regulatory Affairs
Atmos Energy Corporation
3275 Highland Pointe Drive
Owensboro, KY 42303

Tyson Kamuf
Sullivan, Mountjoy, Stainback & Miller PSC
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302-0727
Phone: (270) 926-4000
Facsimile: (270) 683-6694
tkamuf@smsmlaw.com

Counsel for Big Rivers Electric Corporation and its Member distribution cooperatives: Jackson Purchase Energy Corporation, Kenergy Corp. and Meade County Rural Electric Cooperative Corporation

Albert A. Burchett

Albert A. Burchett
Albert A. Burchett, Attorney at Law
P.O. Box 346
Prestonsburg, KY 41653
Telephone: (606) 874-9701

Counsel for Big Sandy RECC

Howard Downing

Howard Downing
109 South First Street
Nicholasville, KY 40356
Telephone: (859) 885-4619

Counsel for Blue Grass Energy Cooperative Corporation

John S. Pumphrey
Grant, Rose & Pumphrey
51 South Main Street
Winchester, KY 40391
Telephone: (859) 744-6828

Counsel for Clark Energy Cooperative, Inc.

Brooke E. Leslie

Brooke E. Leslie
290 W. Nationwide Blvd
P.O. Box 117
Columbus, Ohio 43215

Richard S. Taylor
225 Capital Avenue
Frankfort, KY 40601

Counsel for Columbia Gas of Kentucky, Inc.

W. Patrick Hauser
W. Patrick Hauser, P.S.C.
200 Knox Street
P.O. Box 1900
Barbourville, KY 40906
Telephone: (606) 546-3811
phauser@barbourville.com

Counsel for Cumberland Valley Electric, Inc.

Robert Watt

Robert M. Watt III
Stoll Keenon Ogden PLLC
300 W. Vine Street, Suite 2100
Lexington, KY 40507-1801
Phone: 859-231-3000
Fax: 859-246-3643
robert.watt@skofirm.com

Counsel for Delta Natural Gas Company, Inc.

Rocco D'Ascenzo
Associate General Counsel
Duke Energy Kentucky, Inc.
139 East Fourth Street,
Cincinnati, OH 45201

David S. Samford
Goss Samford, PLLC
2365 Harrodsburg Road
Suite B325
Lexington, KY 40504

Counsel for Duke Energy Kentucky, Inc.

Mark David Goss
Goss Samford, PLLC
2365 Harrodsburg Road
Suite B325
Lexington, KY 40504
Telephone: (859) 368-7740
mdgoss@gosssamfordlaw.com

Counsel for East Kentucky Power Cooperative, Inc. and South Kentucky Rural Electric Cooperative Corporation

Woodford L. Gardner, Jr.
Richardson Gardner & Alexander
117 East Washington Street
Glasgow, Kentucky 42141
Telephone: 270-651-8884
Facsimile: 270-651-3662
wlg@rgba-law.com

Counsel for Farmers Rural Electric Cooperative Corporation

Marvin W. Suit
Marvin W. Suit
Suit, Price, Price & Ruark, PLLC
207 Court Square
Flemingsburg, KY 41041
Telephone: (606) 849-2338
msuit2@windstream.net

Counsel for Fleming-Mason Energy Cooperative, Inc.

W. Jeffrey Scott
W. Jeffrey Scott, P.S.C.
311 West Main Street
P.O. Box 608
Grayson, KY 41143
Telephone: (606) 474-5194
Facsimile: (606) 474-5196
wjscott@windstream.net

Counsel for Grayson Rural Electric Cooperative Corporation

J. Hadden Dean
Sheehan, Barnett, Dean, Pennington, Little & Dexter, PSC
116 North Third Street
P.O. Box 1517
Danville, KY 40423-1517
Telephone: (859) 236-2641
Facsimile: (859) 236-0081
dean@danvillekylaw.com

Counsel for Inter-County Energy Cooperative Corporation

Clayton O. Oswald
Taylor, Keller & Oswald, PLLC
1306 W. 5th Street, Suite 100
P.O. Box 3440
London, KY 40743-3440
Telephone: (606) 878-8844
Fax: (606) 878-8850
coswald@tkolegal.com

Counsel for Jackson Energy Cooperative

R. Benjamin Crittenden
Stites & Harbison PLLC
421 W. Main Street
P.O. Box 634
Frankfort, KY 40602-0634
Phone: 502-223-3477
Fax: 502-223-4388
e-mail: rcrittenden@stites.com

Counsel for Kentucky Power Company

Dated: February 27, 2015

Respectfully submitted,

By: Allyson K Sturgeon

W. Duncan Crosby III
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, KY 40202
Telephone: (502) 560-4263
Fax: (502) 627-8754
duncan.crosby@skofirm.com

– and –

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088
Fax: (502) 627-3367
allyson.sturgeon@lge-ku.com

Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

Gregory D. Allen
P.O. Box 585
Salyersville, KY 41465
Telephone: (606) 349-8000
gregallenlaw@foothills.net

Counsel for Licking Valley Rural Electric Cooperative Corporation

John J. Scott
John J. Scott, PSC
108 East Poplar Street
P.O. Box 389
Elizabethtown, KY 42702-0389
Telephone: (270) 765-2179
john@johnscottlaw.org

Counsel for Nolin Rural Electric Cooperative Corporation

James M. Crawford
Crawford & Baxter, P.S.C.
523 Highland Avenue
P.O. Box 353
Carrollton, KY 41008
Telephone: (502) 732-6688
Fax: (502) 732-6920
CBJ523@aol.com

Counsel for Owen Electric Cooperative, Inc.

John Douglas Hubbard

John Douglas Hubbard
Fulton, Hubbard & Hubbard
117 E. Stephen Foster Avenue
Bardstown, KY 40004
Telephone: (502) 348-6457
Facsimile: (502) 348-8748
jdh@bardstown.com

Counsel for Salt River Electric Cooperative Corporation

Donald T. Prather
Mathis, Riggs, Prather & Ratliff, PSC
500 Main Street, Suite 5
Shelbyville, KY 40065
Telephone: (502) 633-5220
dprather@iglou.com

Counsel for Shelby Energy Cooperative, Inc.

Robert Spragens, Jr.
Spragens & Higdon, P.S.C.
P.O. Box 681
Lebanon, KY 40033
Telephone: (270) 692-3141
Facsimile: (270) 692-6693
rspragens@spragenshigdowlaw.com

Counsel for Taylor County Rural Electric Cooperative Corporation

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC INVESTIGATION OF THE	)	Case No. 2018-00044
REASONABLENESS OF THE ENERGY	)	
EFFICIENCY AND CONSERVATION RIDER OF	)	
COLUMBIA GAS OF KENTUCKY, INC.		

PREPARED DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Brooke E. Wancheck,
Assistant General Counsel
P.O. Box 117
290 W. Nationwide Blvd.
Columbus, Ohio 43216-0117
Telephone: (614) 460-5558
E-mail: bwancheck@nisource.com

Attorney for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

July 16, 2018

ATTORNEY GENERAL
EXHIBIT 7

PREPARED DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

Q: Please state you name and business address.

A: My name is William Steven Seelye, and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

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

A: I am the managing partner for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q: On whose behalf are you testify in this proceeding?

A: I am testifying for Columbia Gas of Kentucky, Inc. ("Columbia Gas" or "Company"), which provides natural gas sales and transportation services in Kentucky.

Q: Please describe your educational and professional background.

A: I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed or supervised the preparation of cost of service and rate studies for over 150 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. A more detailed description of my qualifications is included in Exhibit Seelye-1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 75 regulatory proceedings in 11 different jurisdictions including the Kentucky Public Service Commission ("Commission"). A listing of my testimony in other proceedings is included in Exhibit Seelye-1.

Q: Please describe your experience with demand side management (DSM) programs and cost recovery mechanisms.

A: In Kentucky, I have assisted the following utilities with the development of DSM cost recovery mechanisms: Louisville Gas and Electric Company, Kentucky Utilities, Delta Natural Gas Company, and Columbia Gas. I have also developed a DSM cost recovery mechanism for Nova Scotia Power Company. I have assisted numerous utilities in the economic evaluation of their DSM, energy efficiency, and demand-response programs and have worked with utilities in maximizing the benefit derived from their existing demand side management programs. I have also developed time-of-use, interruptible, real-time pricing, cogeneration, and other rates designed to encourage customers to modify their demand and usage patterns.

Q: Did you submit testimony in support of Columbia Gas's current Energy Efficiency and Conservation Rider (EECR).

A: Yes. Columbia Gas proposed its current EECR rate schedule in Case No. 2009-00141, which was a general rate case. I submitted testimony in support of the EECR in that proceeding. I also submitted testimony in Case No. 2016-00107 in connection with the five-year review and renewal of Columbia's programs. In its Order in that proceeding dated October 11, 2016, the Commission approved Columbia's programs through June 30, 2021.

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

A: The purpose of my testimony is to provide a general assessment of the effectiveness of the EECR rate schedule and to recommend that the rider continue to remain in effect in its current form. I will provide a general assessment of the effectiveness of the current level of funding for DSM and energy efficiency programs and of the effectiveness of the programs that have been developed through collaborative processes. I will also comment on the adequacy of the programs on a going forward basis. I will also explain the importance of Columbia Gas's DSM and energy efficiency programs both to Columbia Gas and to its customers. I testify that Columbia Gas's current level of funding for DSM and energy efficiency is reasonable and that the current programs being offered are also reasonable.

Q: Please describe Columbia Gas's EECR rate schedule.

A: Columbia Gas's EECR is applicable to residential customers served under Rate Schedule GSR and commercial customers service under Rate Schedule GSO. It is designed to provide for the recovery of DSM program costs, to provide for the recovery of net revenues from lost sales due to the implementation of DSM programs, and to provide a small incentive for Columbia Gas to implement DSM programs. While the EECR rate schedule is applicable to both residential and commercial rate schedules, Columbia Gas currently offers no Energy Efficiency/Conservation Programs for commercial customers and therefore the applicable EECR charge for commercial rate schedules is zero. Columbia Gas's current EECR schedule is included as Exhibit Seelye-2.

Columbia Gas's EECR provides a dollar-for-dollar recovery of costs incurred by the Company to implement and operate DSM programs that have been approved by the Commission. Because DSM and energy efficiency programs by design result in a reduction in sales to customers, the EECR rate schedule provides for the recovery of revenues from lost sales due to the implementation of those programs. The EECR also provides a small incentive designed to encourage the Company to develop and implement DSM programs and includes a reconciliation adjustment to ensure that there will not be any over- or under-recovery of either DSM program costs or revenues from lost sales under the mechanism.

Columbia Gas's EECR thus consists of the following four components: (1) a Energy Efficiency/Conservation Program Cost Recovery (EECPCR) component that provides for the recovery of DSM program costs, (2) an EECP Revenue from Lost Sales (EECPLS) component that provides for the recovery of revenues from lost sales, (3) an EECP Incentive (EECPI) component that is designed to encourage Columbia Gas to develop and implement DSM programs, and (4) an EECP Balance

Adjustment (EECPBA) that reconciles for any over- or under-recovery of program costs, revenues from lost sales, and incentives.

Q: Is Columbia Gas's EECR rate schedule consistent with the DSM mechanism described in KRS 278.285?

A: Yes. Utilities in Kentucky can propose a DSM cost recovery mechanism pursuant to KRS 278.285. Subsection 2 of KRS 278.285, of states as follows:

> A proposed demand-side management mechanism including:
>
> (a) Recover the full costs of commission-approved demand-side management programs and revenues lost by implementing these programs;
> (b) Obtain incentives designed to provide financial rewards to the utility for implementing cost-effective demand-side management programs; or
> (c) Both of the actions specified
>
> may be reviewed and approved by the commission as part of a proceeding for approval of new rate schedules initiated pursuant to KRS 278.190 or in a separate proceeding initiated pursuant to this section which shall be limited to a review of demand-side management issues and related rate-recovery issues as set forth in subsection (1) of this section and in this subsection.

In accordance with KRS 278.285, Columbia Gas's EECR provides for recovery of the full cost of commission-approved demand-side management programs, provides for recovery of revenue lost by implementing these programs, and allows the Company to obtain incentives designed to financial rewards for implementing cost-effective demand-side management programs. Also, consistent with the practice for most cost recovery mechanisms that have been approved by the Commission over the years, the EECR rider includes an over- and under-recovery mechanism that ensures that the Company doesn't collect more or less than the amounts determined by the other components of the EECR.

Q: **Without a DSM cost recovery mechanism, do utilities have an incentive to pursue demand-side management strategies that would reduce sales and encourage customer conservation?**

A: No. In traditional regulation, utilities have an incentive to increase retail sales relative to historical test-year levels that were used for calculating their base rates. The incentive for utilities to maximize the "throughput" of gas sales and transportation volumes in an attempt to increase net margins is referred to as a "throughput incentive". Utility profits are reduced when demand side management and energy efficiency programs reduce sales and transportation volumes from levels that would have been obtained without these programs. Under traditional regulation, there is an incentive for utilities to avoid programs aimed at reducing sales. It is critical to address this throughput incentive and to provide for DSM program cost recovery if the utility is to be actively involved in demand side management and energy efficiency programs that encourage customers to conserve energy, utilize the most efficient appliances and manage their bill

Q: Is Columbia Gas's EECR rate schedule still adequate?

A: Yes. The EECR rate schedule still reflects sound ratemaking principles for encouraging Columbia to promote DSM and energy conservation programs; it is fully consistent with provisions set forth in Section 2 of KRS 278.285; and it is consistent with DSM and energy conservation cost recovery mechanisms that have been approved for other gas and electric utilities that pass the Total Resource Cost Test.

Q: Do you recommend any changes to the EECR rate schedule?

A: No.

Q: Please describe Columbia Gas's current DSM and energy efficiency programs.

A: Columbia Gas offers three programs targeted to residential customers taking service under Rate Schedule GSR -- (i) High-Efficiency Appliance Rebates, (ii) a Home Energy Audit program, and (iii) a Low-Income High Efficiency Furnace Replacement program. The Energy Audit and the High-Efficiency Furnace Rebate programs are generally available to all customers taking service under Rate

Schedule GSR. The Low-Income High Efficiency Furnace Replacement program is only available to residential customers that receive Low Income Home Energy Assistance Program (LIHEAP) funding.

Q: **Please describe the High-Efficiency Appliance Rebates offered by Columbia Gas.**

A: Under the High-Efficiency Appliance Rebate Program, Columbia Gas currently provides the following rebates for the installation of high-efficiency appliances:

Appliance	Efficiency Level	Size	Rebate
Forced Air Furnace	≥ 90%	≥ 30,000 Btu	$400
Dual Fuel Furnace	≥ 90%	≥ 30,000 Btu	$300
Space Heater	99%	≥ 10,000 Btu	$100
Gas Logs	99%	≥ 18,000 Btu	$100
Gas Fireplace	≥ 90%	≥ 18,000 Btu	$100
Tank Hot Water Heater	0.62 Energy Factor	≥ 40 gallons	$200
Power Vent Hot Water Heater	0.62 Energy Factor	≥ 40 gallons	$250
On Demand Hot Water Heater	0.67 Energy Factor	N/A	$300

Table 1

These rebates incentivize customers to install appliances that are more efficient yet more costly to install than standard appliances. These rebates help off-set the higher installation cost of higher-efficiency alternatives.

Q: Are appliance rebates developed as part of a collaborative process?

A: Yes. Columbia Gas formed a DSM collaborative group to discuss new programs and the modification of existing programs. The implementation of any new rebate would be discussed at a collaborative meeting consisting of community action councils, gas marketers, the Office of the Attorney General, or other interested parties.

Q: How much did Columbia Gas spend on High-Efficiency Appliance rebates during the most recent program year?

A: For the 12-month period ended December 31, 2017, Columbia Gas spent $396,224 on High-Efficiency Appliance rebates.

Q: Do you recommend that Columbia Gas continue to offer these High Efficiency Appliance Rebates?

A: Yes.

Q: Please describe the Columbia Gas's Energy Audit program.

A: Under the Energy Audit Program, Columbia Gas funds free walk-through energy audits (now also referred to as "check-ups) to residential customers. The audits are performed by a qualified outside contractor selected by the Company. These audits encompass the following services:

- An analysis of the dwelling's usage history and the detection of any abnormalities or trends relative to the square footage, load and surrounding dwelling usage trends;
- Checking for proper changes of the heating system filtering devices and clearance from obstructions of all return air registers;
- Inspection of outer wall switch plates and outlets for insulation protection or gasket installation;
- Checking of ceiling insulation levels;
- Inspection of duct systems;
- Checking of exterior windows and doors for unwanted leakage and heat loss;
- Identification of areas of high energy loss through thermal imaging;
- Providing options and recommendations to the occupant;
- Providing the occupant with an audit kit consisting of caulk, switch plate and outlet gaskets, electric outlet plugs and weather stripping.

Q: How does Columbia Gas inform residential customer about the existence and benefits of the program?

A: Columbia Gas uses a number of communication channels to inform residential customers about the program, including commercial and public radio notices, online advertisement (e.g. the Weather Channel), Public Television notices, customer in-bill newsletters, the Company's website, magnets on service vehicles, and direct mail. These channels are similar to those used by other utilities in Kentucky.

Q: Do you recommend that Columbia Gas continue to offer its Energy Audit Program?

A: Yes. Energy audits are important tools for helping customers to conserve energy and customers provide favorable feedback in response to the audits or "Home Energy Check-ups".

Q: Please describe the Low-Income High Efficiency Furnace Replacement Program.

A: Under the Low-Income High Efficiency Furnace Replacement Program, Columbia Gas currently provides up to $2,800 toward the cost of installing a high efficiency forced air furnace of 90 percent efficiency or higher for a qualifying low-income customer. Columbia Gas partners with the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc ("CAC") to provide this service. The CAC identifies potential customers, qualifies the customers, and works with its contractors to replace existing furnaces with high efficiency forced air furnaces of 90 percent efficiency or higher.

Q: Why is the Low-Income High Efficiency Furnace Replacement Program important part of Columbia Gas's DSM and energy efficiency program?

A: Low-income customers often live in older homes with older, less efficient furnaces. I have conducted study after study for utilities across the U.S. and have found that customers receiving LIHEAP funding use more gas and electric energy than the average residential usage. One of the reasons for this is that LIHEAP customers often have inefficient appliance stocks. Because people receiving LIHEAP funding are the customers who are typically the least able financially to replace inefficient furnaces, this program fulfills an important need in Columbia Gas's service territory for improving energy efficiency and thus reducing the customer's bill. While the High-Efficiency Appliance Rebate program will incentivize customers who have sufficient financial resources to install more efficient appliances, for low-income customers rebates are simply not enough to encourage the efficient replacement of aging, inefficient furnaces.

Q: How much did Columbia Gas spend on its Low-Income Furnace Replacement program during the most recent program year?

A: For the 12-month period ended October 31, 2017, Columbia Gas spent $200,845 on its Low-Income Furnace Replacement program.

Q: Do you recommend that Columbia Gas continue to offer its Low-Income Furnace Replacement program?

A: Yes.

Q: How much is Columbia Gas's total annual budget for its Energy Efficiency/Conservation Program?

A: Columbia Gas's total annual budget for all three programs is $908,000. This annual budget has not changed since the EECR rate schedule was first introduced in November 2009.

Q: Have you prepared an exhibit showing the annual expenditures for each program since the inception of the Energy Efficiency/Conservation Program?

A: Yes. Exhibit Seelye-3 shows the annual expenditures for each program along with administrative costs. The following table shows the average annual direct cost for each program.

Program	Average Annual Direct Expenditure For Program
High-Efficiency Appliance Rebates	$ 86,659
Home Energy Audit program	$ 415,436
Low-Income High Efficiency Furnace Replacement	$ 298,854
Total Direct Expenditures	$ 800,948

Table 2

Q: Is the overall level spent by Columbia Gas on conservation and energy efficiency programs reasonable?

A: Yes, I would characterize Columbia Gas's DSM and energy efficiency program as modest yet reasonable. Without introducing programs that provide greater benefits toward reducing the rates of all customers on Columbia Gas's system, I would not recommend expanding the program.

Q: Have you prepared an exhibit showing the number of participants for each program since the inception of the Energy Efficiency/Conservation Program?

A: Yes. Exhibit Seelye-4 shows the number of participants for each program along with administrative costs. The following table shows the total participants for each program since the EECR rate schedule was implemented in 2009:

Program	Total Participants
High-Efficiency Appliance Rebates	8,336
Home Energy Audit program	2,580
Low-Income High Efficiency Furnace Replacement	970
Total Participants	11,886

Table 3

Q: Are the program participants widely dispersed throughout Columbia Gas's service territory?

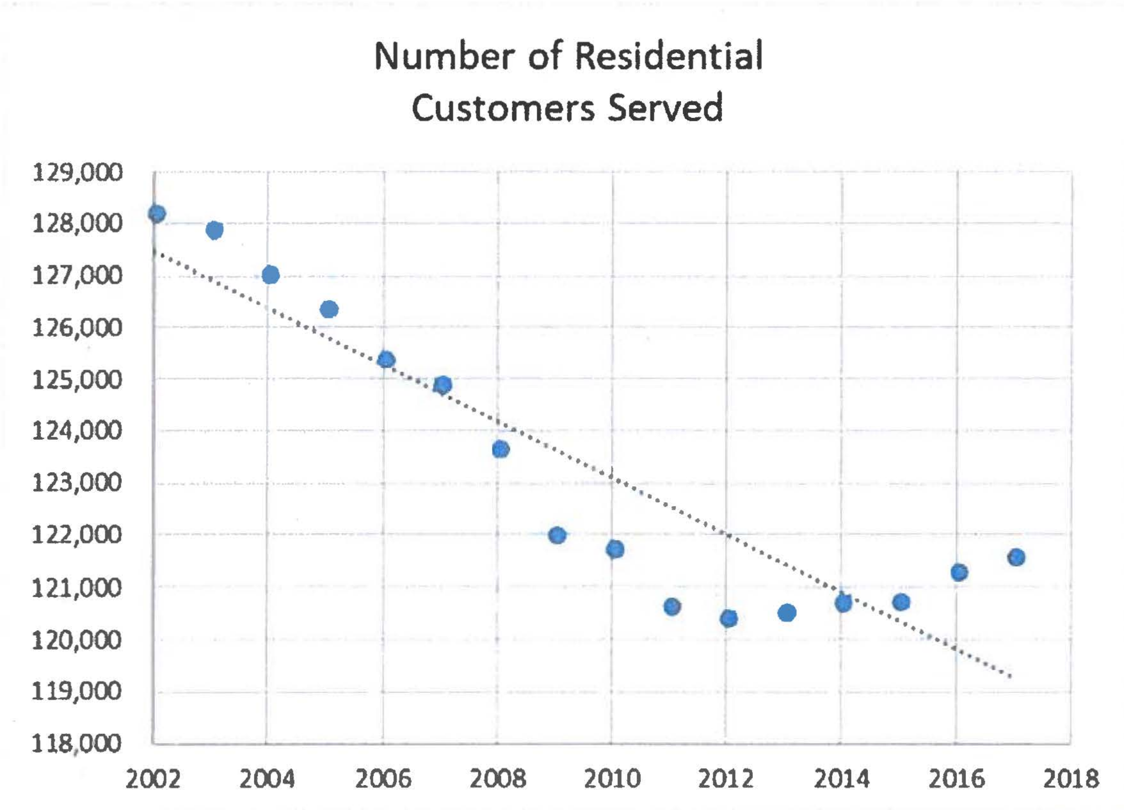
A: Yes. Residential customers in all of Columbia's service area participated in Columbia Gas's Energy Efficiency/Conservation Program. Participants by county are shown in Exhibit Seelye-5.

Q: Why are Columbia's DSM and energy conservation programs important to the Company and its customers?

A: As previously discussed, Columbia provides three DSM and energy conservation programs: (i) High-Efficiency Appliance Rebates, (ii) a Home Energy Audit program, and (iii) a Low-Income High Efficiency Furnace Replacement program. The High-Efficiency Appliance Rebates and the Low-Income High Efficiency Furnace Replacement program are particularly important to help ensure that Columbia continues to provide gas service for major appliances. The harsh reality for gas utilities is that it has become increasingly more difficult to retain existing customers and to pipe out service to new homes. In September 25, 2014, the U.S. Energy Information Administration (EIA) published a report titled "Everywhere but the Northeast, Fewer Homes Choose Natural Gas as Heating Fuel" which indicated that new customers were showing a preference for electric service over natural gas service. See Exhibit Seelye-6. The report stated that "[p]art of the national change in heating fuel choice can be attributed to population migration farther west and south. But even within Census regions, electricity has been gaining market share at the expense of natural gas." Columbia is no different from other gas utilities in finding it difficult to encourage builders to install gas appliances and encouraging existing customers to replace old or failing natural gas appliances with *natural gas appliances* rather than with *electric appliances*. For this reason, the rebates provided by the High-Efficiency Appliance Rebates and the Low-Income High Efficiency Furnace Replacement program to install natural gas appliances are of significant strategic importance to Columbia. These incentive programs also benefit participants by encouraging them to install high efficiency appliances and they benefit non-participants by helping to ensure that the utility's fixed costs are not spread over a smaller and smaller sales volumes because of customers abandoning natural gas in favor of electric service.

Q: Please explain how a gas utility's rates are affected when they lose appliances to electric utilities?

A: A gas utility must install fixed assets to provide service to its customers. Specifically, the utility must install distribution mains, services, and meters to connect new customers. When an existing customer switches its gas water heater or furnace to an electric water heater or furnace, or when a customer leaves Columbia's system by disconnecting gas service altogether, the fixed costs of the facilities installed to provide service to the customer do not automatically disappear. These fixed costs must be spread to the utility's other customers, thereby putting upward pressure on the utility's rates. Therefore, in terms of the distribution delivery rates that customers pay for gas service, the utility and its customers are better off if the utility can continue to serve gas appliances. Similarly, a utility's fixed costs are spread over a larger customer base (i.e., over more MCF or over more customer-months to which the customer charge is applied) when new customers are added to the system. This is particularly true when customers are added to an existing line extension. During the past couple of decades, Columbia's residential customer base has decreased from 128,241 customers as of December 31, 2002 to 121,630 as of December 31, 2017. (Columbia served 119,997 residential customers as of June 30, 2018, but the dip from December 2017 to June 2018 would in part be related to seasonal reductions in customers during the summer months.) The decline in residential customers from 2002 to 2017 is demonstrated in the following graph (Graph 1):



Graph 1

This graph illustrates the difficulty that Columbia has faced in retaining existing residential customers and attracting new residential customers. The graph also strongly suggests that Columbia's appliance rebates, which were first implemented in 2009, may have helped quell the steep decline in the number of residential customers that Columbia has seen during the last couple of decades. Columbia firmly believes that its appliance rebate and replacement programs have been key reasons that the decline in residential customers has abated since the implementation of the rebate and replacement programs. Columbia is now experiencing an increase in the number of residential customers that it serves, in large part, Columbia strongly believes, because its rebate and replacement programs place gas appliances on a more favorable footing in comparison to electric appliances.

Obviously, retaining existing customers, retaining gas appliances, and attracting new customers are critically important to a stand-alone gas utility. It is Columbia's position that offering appliance rebates and incentives is important to all three of these objectives. Rebates and replacement programs encourage existing customers to replace their current *gas* appliances with new *gas* appliances rather than with new *electric* appliances when their appliances fail. Incentives encourage customers and contractors building new homes to install *gas* appliances rather than electric appliances that generally have lower up-front installed costs. As mentioned earlier, an impediment to gas appliances being installed in new residential construction is the relatively higher up-front cost of gas appliances in comparison to electric appliances. Ultimately, Columbia and its existing customer base are better off if the Company can retain existing customers and add new customers.

Q: Could you provide an example illustrating how offering incentives can benefit non-participants by ensuring that lost fixed cost recovery is not spread to other customers?

A: Yes. Columbia competes with some East Kentucky Power Cooperative's ("EKPC's") member systems to serve space heating and water heating appliances in critical growth areas outside of the municipal regions served by Kentucky Utilities Company and Kentucky Power Company. (Columbia's service territory overlaps with some EKPC member systems, Kentucky Utilities and Kentucky Power, but the suburban and rural areas served by EKPC represent significant growth areas for Columbia.) When Columbia loses a gas appliance to one of its electric competitors, the fixed cost of Columbia's backbone delivery system must be spread to Columbia's other customers. Columbia believes that its appliance rebate programs have been instrumental in preventing the loss of current and prospective customers. During 2017, Columbia residential customers used on average 62 Mcf of natural gas. If Columbia loses a customer using 62 Mcf to one of EKPC's member systems, then the fixed costs recovered from the customer must be spread to the Columbia's other customers. Specifically, Columbia recovers approximately $628.48 in fixed annual costs from a residential customer that uses 62 Mcf, as shown below:

Customer Charge	12 Cust-Months @$16/Mo	= $192.00
Delivery Charge	62 Mcf @ $7.04	= $436.48
Total Fixed Cost Recovery		**= $628.48**

Therefore, if Columbia were to lose 5,000 customers, as it did from 2002 through 2009 prior to the implementation of its rebate programs (see above), then Columbia would need to collect approximately $3.1 million in annual revenues from other customers. This corresponds to an annual increase in rates of $25.31 for each of Columbia's remaining customers ($3.1 million ÷ 122,500 customers = $25.31 per customer.) In contrast, Columbia's residential customers are currently charged $0.55 per customer per month for its energy efficiency and conservation programs. This equates to $6.60 per year. If Columbia's rebate programs can prevent the loss of customers that it experienced during the 2002 to 2009 timeframe, then Columbia's existing customers would realize a net annual savings of $18.71 per customer from the rebate programs.

Q: What are some of the reasons that customers would choose electric appliances over gas appliances even though gas appliances might be less costly in the long run?

A: The up-front cost of electric appliances is often lower than for gas appliances, even though high-efficiency gas appliances often perform as well or better than electric appliances. The lower up-front cost of electric appliances provides a strong inducement for builders to install electric appliances over gas appliances. In general, builders will often install lower efficiency appliances instead of high efficiency appliances because of the lower up-front costs. See Lekov et al., "Economics of Residential Gas Furnaces and Water Heaters in US New Construction Market", *Energy Efficiency* (2010) 3:203-222. See Exhibit Seelye-7. Also, residential customers will often opt for lower up-front-cost electric appliances when replacing existing gas appliances. Furthermore, when servicing a water heater that needs replacing, plumbers are more likely to carry electric water heaters in their service trucks than gas water heaters. Rebates will often allow customers to choose what is more cost effective than what is simply more convenient.

Q: Are the impacts of the cost to participants and non-participants captured in any of the California Tests?

A: The Total Resource Cost ("TRC") Test evaluates the overall cost impact to participants and non-participants.

Q: What is the result of the TRC Test for Columbia Gas' programs?

A: As provided in its response to Item 3 of the Commission Staff's Third Request for Information, Columbia Gas' programs pass the TRC Test and show the value to all customers, both participants and non-participants of Columbia Gas' programs.

Q: Does this complete your prepared direct testimony?

A: Yes

WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Principal and Managing Partner
The Prime Group, LLC
(1996 to 2012) (2015-Present)
(Associate Member 2012-2015)

Provides consulting services in the areas of tariff development, regulatory analysis, revenue requirements, cost of service studies, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic resource and marketing plans. Assist with resource planning and cost benefit analyses for generation investment projects. Performs economic analyses evaluating the costs and benefits of an electric generation projects; performs business practice audits for electric utilities, gas utilities, and independent transmission organizations, including audits of production cost modeling, fuel procurement practices and controls, and wholesale marketing procedures. Assists investor-owned utilities in the development of testimony regarding the prudence of power supply decisions and of investments in specific generation and distribution assets.

Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 150 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Instructor in Mathematics
Walden School and Private Instruction
(2012-2015)

Taught advanced placement calculus, linear algebra, pre-calculus, college algebra and differential equations.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education
Bachelor of Science Degree in Mathematics, University of Louisville, 1979
66 Hours of Graduate Level Course Work in Electrical and Industrial Engineering and Physics.

Associations
Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

Submitted expert report in No. 14-CV-30031 before District Court, Prowers County, State of Colorado, on behalf of Arkansas River Power Authority in the *City of Lamar et al v. Arkansas River Power Authority regarding* power planning and operations.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER11-2127-000 concerning transmission rates proposed by Terra-Gen Dixie Valley, LLC.

Submitted testimony in Docket No. ER11-2779 on behalf of Southern Illinois Power Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Submitted testimony in Docket No. ER11-2786 on behalf of Norris Electric Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Submitted testimony in Case No. 2009-00548 on behalf of Kentucky Utilities Company and in Case No. 2009-00549 on behalf of Louisville Gas and Electric

Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2010-00116 on behalf of Delta Natural Gas Company concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony in Case No. 2011-00036 on behalf of Big Rivers Electric Cooperative concerning cost of service, rate design, pro-forma TIER adjustments, temperature normalization, and support of MISO Attachment O.

Submitted testimony in Case No. 2016-00107 on behalf of Columbia Gas Company of Kentucky regarding a tariff application to the continue its energy efficiency and conservation rider and programs.

Submitted testimony in Case No. 2016-00274 on behalf of Kentucky Utilities Company and Louisville Gas and Electric Company in support of community solar rates.

Submitted testimony in Case No. 2016-00370 on behalf of Kentucky Utilities Company and in Case No. 2016-00371 on behalf of Louisville Gas and Electric Company regarding electric and gas class cost of service studies and proposed rates.

Submitted rebuttal testimony in Case No. 2018-00050 on behalf of South Kentucky Rural Electric Cooperative Corporation regarding the regulatory application of the filed rate doctrine and cost shifts to other electric cooperatives related to a proposed purchased power agreement.

Maryland — Submitted direct testimony in PSC Case No. 9234 on behalf of Southern Maryland Electric Cooperative regarding a class cost of service study.

Nevada: — Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 10-06001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate cases.

Submitted direct testimony in Case No. Docket No. 11-06006 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

New Mexico Submitted testimony in support of filing of Advice Notice No. 60 on behalf of Kit Carson Electric Cooperative, Inc.

Submitted direct testimony in Case No. 15-00375-UT on behalf of Kit Carson Electric Cooperative, Inc. regarding revenue requirements, the need for a rate increase, class cost of service study, apportionment of the revenue increase to the classes of service, and rate design.

Submitted testimony in Advice Notices in Case No. 15-00087-UT on behalf of Jemez Mountain Electric Cooperative in support of tribal right of way cost recovery surcharge mechanisms.

Submitted direct testimony in Case. No. 16-00065-UT on behalf of Kit Carson Electric Cooperative in support of an application for continuation of its fuel and purchased power cost adjustment clause.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2011-00013 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, and rate design.

ENERGY EFFICIENCY AND CONSERVATION RIDER
ENERGY EFFICIENCY/CONSERVATION PROGRAM COST RECOVERY
(Continued)

MODIFICATIONS TO EECPRC (continued)

Each change in the EECPRC shall be placed into effect with meter readings on and after the effective date of such change.

Adjustment Factors: Per Meter per Billing Period

Residential:

EECPCR	$0.61	
EECPLS	$0.03	
EECPI	$0.12	
EECPBA	($0.21)	R
Total EECPRC for Residential Customers	$0.55	R

Commercial:

EECPCR	$0.00
EECPLS	$0.00
EECPI	$0.00
EECPBA	$0.00
Total EECPRC for Commercial Customers	$0.00

DATE OF ISSUE January 20, 2017

DATE EFFECTIVE January 31, 2017

ISSUED BY /s/ Herbert A. Miller, Jr.
TITLE President

KENTUCKY
PUBLIC SERVICE COMMISSION
Talina R. Mathews
EXECUTIVE DIRECTOR
Talina R. Mathews
EFFECTIVE
1/31/2017
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Exhibit Seelye-3

Columbia Gas of Kentucky, Inc.
Energy Efficiency/Conservation Program Costs

Program Period Year End	Energy Audit Program	High-Efficiency Appliance Rebate Program	Furnace Replacement Program	Direct Program Cost	CKY Program Administration	Total Program Cost
Oct-10	$ 53,189	$ 189	$ 58,246	$ 111,624	$ -	$ 111,624
Oct-11	171,252	616,153	195,801	983,206	2,500	985,706
Oct-12	29,949	442,839	296,421	769,209	27,694	796,903
Oct-13	302,235	443,083	704,940	1,450,258	20,325	1,470,583
Oct-14	40,257	498,650	531,170	1,070,077	73,170	1,143,247
Oct-15	32,189	451,731	252,645	736,565	18,397	754,962
Oct-16	45,940	474,616	150,760	671,316	37,807	709,123
Oct-17	18,262	396,224	200,845	615,331	68,168	683,499
Total	$ 693,273	$ 3,323,485	$ 2,390,828	$ 6,407,586	$ 248,061	$ 6,655,647
Average Annual	$ 86,659	$ 415,436	$ 298,854	$ 800,948	$ 31,008	$ 831,956

Exhibit Seelye-4

Columbia Gas of Kentucky, Inc.
Energy Efficiency/Conservation Program Participants

Program Period Year End	Energy Audit Program	High-Efficiency Appliance Rebate Program	Furnace Replacement Program	Total Program Participants
Oct-10	183	-	24	207
Oct-11	277	1,429	91	1,797
Oct-12	158	1,138	160	1,456
Oct-13	1,399	1,194	264	2,857
Oct-14	252	1,248	198	1,698
Oct-15	116	1,179	98	1,393
Oct-16	76	1,131	59	1,266
Oct-17	119	1,017	76	1,212
Total	2,580	8,336	970	11,886
Average Annual	323	1,042	121	1,486

Columbia Gas of Kentucky, Inc.
Energy Efficiency/Conservation Program Participants

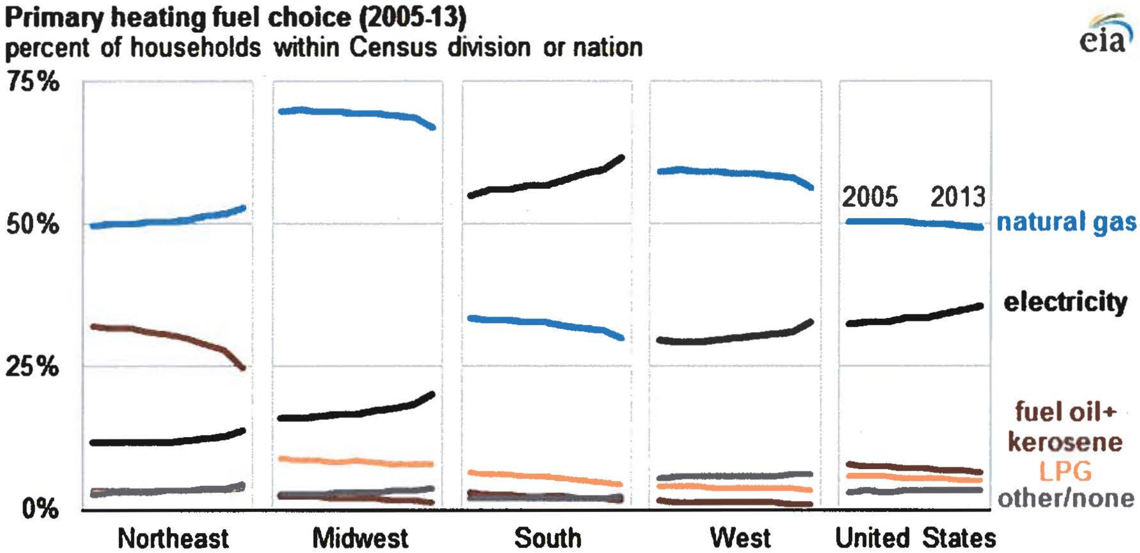
County	Appliance Rebate Program	Low-Income Furnace Replacement Program	Energy Audit Program	All Programs
Bourbon	124	90	37	251
Boyd	795	38	145	978
Bracken	4	-	-	4
Carter	1	-	-	1
Casey	1	-	-	1
Clark	220	12	88	320
Clay	2	-	-	2
Estill	25	11	9	45
Fayette	5,180	736	1,658	7,574
Floyd	5	1	16	22
Franklin	495	3	247	745
Grant	1	-	-	1
Greenup	437	18	107	562
Harrison	65	53	24	142
Jessamine	152	-	27	179
Johnson	-	-	1	1
Knott	1	-	3	4
Laurel	1	-	-	1
Lawrence	16	1	11	28
Lewis	-	-	2	2
Madison	15	3	7	25
Martin	3	-	2	5
Mason	89	-	19	108
Montgomery	115	-	25	140
Nicholas	1	2	-	3
Perry	1	-	-	1
Pike	6	-	4	10
Scott	283	2	69	354
Taylor	5	-	2	7
Woodford	293	-	77	370
Total	8,336	970	2,580	11,886

U.S. Energy Information Administration

Today in Energy

September 25, 2014

Everywhere but Northeast, fewer homes choose natural gas as heating fuel



Source: U.S. Energy Information Administration, based on Census Bureau American Community Survey
Note: Geographic areas based on Census regions. LPG is liquefied petroleum gas.

On a national basis, natural gas has long been the dominant choice for primary heating fuel in the residential sector. Lately, electricity has been gaining market share while natural gas, distillate fuel oil, kerosene, and liquefied petroleum gas (propane) have declined.

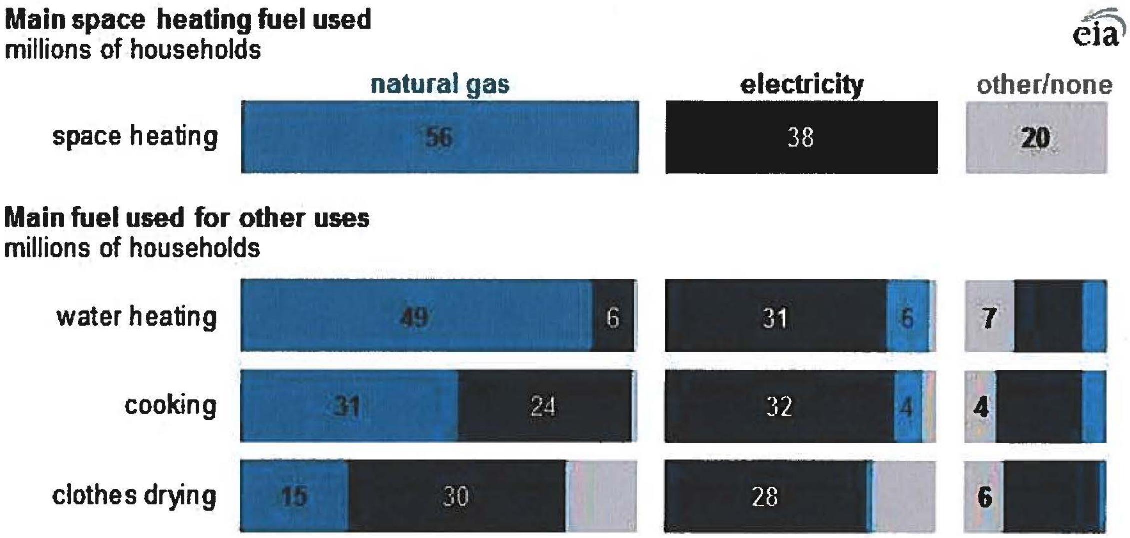
Part of the national change in heating fuel choice can be attributed to population migrations farther west and south. But even within Census regions, electricity has been gaining market share at the expense of natural gas. The Northeast is the exception, as both natural gas and electricity have been increasing while distillate fuel oil and kerosene have declined.

In the Midwest, most homes are heated by natural gas. The Midwest also has the highest percentage of homes heated by propane, although both natural gas and propane have lost market share to electricity since 2005. The South is the only Census region where electricity is the main space heating fuel in the majority of homes. Heating fuel preferences in the West largely mirror the national average, although households in the West are more likely to use wood as their primary heating fuel or to report not using heating equipment at all.

Improvements in electric heat pump technology have improved efficiency and extended the range of temperatures that heat pumps can operate in before resorting to back-up heating, which is most often an electric resistance element similar to that used in a toaster or an electric dryer. Electric resistance heating is effective but relatively expensive to operate.

Heating fuel choice reflects decisions made by home builders and owners. EIA data show that homes built since 1970 use electricity and natural gas as their main heating fuel in roughly equal proportions. Often the choice of heating fuel in new construction has long-term implications, as fuel switching can be expensive. In addition to buying new equipment and removing old equipment, ductwork, pipes, flues, pumps, and fans may need to be installed or removed.

Space heating is the largest portion of household energy use in most areas of the country, and the choice of main heating fuel also influences the fuels chosen for other end uses such as water heating, cooking, and clothes drying. EIA's Residential Energy Consumption Survey (RECS) collects data on fuels used for these purposes, which account for about 65% of 2014 residential delivered energy consumption. The most recent survey data show that homes using natural gas as their main space heating fuel are more likely to also use natural gas for other purposes. Nationally, only 20% of clothes dryers use natural gas, but in homes with natural gas as their main space heating fuel, that percentage increases to 34%. Of the homes using electricity as their primary heating fuel, about 96% used electric clothes dryers.



Source: U.S. Energy Information Administration, Residential Energy Consumption Survey 2009

Principal contributor: Owen Comstock

Energy Efficiency (2010) 3:203–222
DOI 10.1007/s12053-009-9061-y

Economics of residential gas furnaces and water heaters in US new construction market

**Alex B. Lekov · Victor H. Franco ·
Gabrielle Wong-Parodi · James E. McMahon ·
Peter Chan**

Received: 6 March 2009 / Accepted: 9 October 2009 / Published online: 30 October 2009

Abstract New single-family home construction represents a significant and important market for the introduction of energy-efficient gas-fired space heating and water-heating equipment. In the new construction market, the choice of furnace and water-heater type is primarily driven by first cost considerations and the availability of power vent and condensing water heaters. Few analysis have been performed to assess the economic impacts of the different combinations of space and water-heating equipment. Thus, equipment is often installed without taking into consideration the potential economic and energy savings of installing space and water-heating equipment combinations. In this study, we use a life-cycle cost analysis that accounts for uncertainty and variability of the analysis inputs to assess the economic benefits of gas furnace and water-heater design combinations. This study accounts not only for the equipment cost but also for the cost of installing, maintaining, repairing, and operating the equipment over its lifetime. Overall, this study, which is focused on US single-family new construction households that install gas furnaces and storage water heaters, finds that installing a condensing or power-vent water heater together with condensing furnace is the most cost-effective option for the majority of these houses. Furthermore, the findings suggest that the new construction residential market could be a target market for the large-scale introduction of a combination of condensing or power-vent water heaters with condensing furnaces.

A. B. Lekov (✉) · V. H. Franco · G. Wong-Parodi ·
J. E. McMahon · P. Chan
Lawrence Berkeley National Laboratory,
One Cyclotron Road,
Berkeley, CA 94720, USA
e-mail: ABLekov@lbl.gov
URL: http://www.lbl.gov/

V. H. Franco
e-mail: VHFranco@lbl.gov
URL: http://www.lbl.gov/

G. Wong-Parodi
e-mail: GWong-Parodi@lbl.gov
URL: http://www.lbl.gov/

J. E. McMahon
e-mail: JEMcMahon@lbl.gov
URL: http://www.lbl.gov/

P. Chan
e-mail: PTChan@lbl.gov
URL: http://www.lbl.gov/

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Introduction

Residential space and water heating account for 39% of total residential primary energy consumption and

91% of all residential gas[1] consumption in the USA (4.9 quads in 2007; US Department of Energy 2009a). A gas furnace and a gas water heater are the most common combination of space and water-heating equipment in existing single-family homes, where on average about half of all new homes (about 0.8 million from 1999 to 2007) are installed with this combination (US Department of Energy 2005; US Department of Commerce 2008).

In new single-family construction, the builder, contractor, or the architect is primarily responsible for the selection of space and water-heating equipment (Ashdown et al. 2004). Several criteria play a role in the equipment choice: lowest first cost (equipment and installation cost), familiarity with equipment by installers, code acceptability, and home buyer preference (Ghent and Keller 1999). As consumers' interest grows for equipment choices that offer significant long-term energy cost savings and reduce environmental impact, builders can find it beneficial to market their homes with more efficient equipment. In addition to consumer pressure, the federal Energy Star program and state's building codes are providing incentives and promoting more efficient equipment. Despite this, two factors contribute to the routine failure to select both more efficient furnaces and more efficient water heaters: lack of availability of condensing water heaters and lack of awareness of the economic impacts of the different combinations of space and water-heating equipment.

This study applies a life-cycle cost (LCC) analysis[2] to calculate the economic advantages and disadvantages to consumers, comparing alternative gas furnace and water-heater combinations installed in new single-family homes. In the past, the US Department of Energy (DOE) has performed separate LCC analysis on residential furnaces and on water heaters (Lekov et al. 2006, 2000). However, little research has been performed to assess the economics of gas space and water-heating equipment combinations regionally and nationally. This study uses data from recent analyses by DOE that examine the energy savings and economic benefits at the household level for six selected furnace and water-heater combinations that include equipment currently available and promoted by the Energy Star program. The study also includes a National Impact Analysis (NIA) to estimate the national energy savings and the national economic impacts from installing different gas furnace and water-heater combinations in new homes.

[1] Includes both natural gas and liquid petroleum gas.

[2] An LCC is a cost/benefit analysis over the lifetime of the equipment from a consumer perspective.

US space heating and water-heating market characterization

The US space heating and water-heating market differs significantly from other major markets (e.g., Europe or Japan). The US market is dominated by air-distribution systems and storage type water heaters, whereas other major markets are dominated by hydronic and heat pump systems.

Space heating

Central heating systems (air distribution and hydronics) in the USA account for 82% of residential heating equipment stock in 2001: 92% of single-family households built from 1980 to 2001 (US Department of Energy 2001) and 98% of all single-family new construction built during 1997–2007 (US Department of Commerce 2008). Most of the remaining heating systems are direct heating equipment (room heaters, wall furnaces, fireplaces, etc.). The US central space heating market is dominated by forced air furnaces (85% of the stock and 97% of all single-family new constructions built during 1997–2007), while hydronics accounts for a smaller fraction (15% of stock and 3% of all single-family new construction built during 1997–2007). Table 1 shows the fraction of heating systems in single-family households by fuel type. These heating systems show significant regional differences. For example, based on US Census Regions (US Department of Commerce 2009), almost all hydronic systems are located in the northeastern US (census region 1), while electric heating equipment dominates the southern US (census region 3; see Table 1).

Water heating

The current stock of residential water-heating equipment is almost entirely storage water heaters (US Department of Energy 2001). The rest of the stock (about 1%) includes all other water-heating catego-

Table 1 US space heating market for single-family households (built from 1980 to 2001)

Heating system types	Fuel	Region 1 (Northeast, %)	Region 2 (Midwest, %)	Region 3 (South, %)	Region 4 (West, %)	National (%)
Central air	Gas	45	91	45	71	59
	Electricity[a]	13	6	48	15	29
	Oil	8	0	0	0	1
	Other	3	0	0	1	0
Hydronics	Gas	5	0	0	1	1
	Oil	12	0	0	0	1
DHE, other[b]	Electricity	9	2	2	5	3
	Gas	0	0	3	2	2
	Oil	2	0	0	0	0
	Other	2	0	1	5	2

Source: RECS 2001 Survey

DHE direct heating equipment

[a] Electric resistance and heat pumps

[b] Other includes solar, wood, and no heating

Table 2 US Water heating market for single-family households (built after 1980)

Fuel	Region 1 (Northeast, %)	Region 2 (Midwest, %)	Region 3 (South, %)	Region 4 (West, %)	National
Gas	48	81	46	80	60
Electric	34	19	54	19	38
Oil	10	0	0	0	1
Combination/other	8	0	0	0	1

Source: RECS 2001 Survey

ries: tankless water heaters, combined space heating and water-heating appliances,[3] solar water heating, district heating, and others. As shown in Table 2, storage water heaters in single-family households built after 1980 are about 60% gas-fired, 38% electric, 1% fuel oil, and 1% combination or other.[4] Regionally, gas-fired water heating is dominant in all regions except in the South.

Availability of natural gas is a major driver in the selection of the heating and water-heating equipment. Newly constructed homes with natural gas access in almost all cases are equipped with gas-fired furnaces and water heaters. Regionally the gas households are mostly in the Northern and Western parts of USA. As shown in Fig. 1, for single-family houses built after 1980, the dominant combination of water heating and space heating is a gas furnace with a gas water heater (53%) followed by an electric furnace or heat pump and electric water heater (26%; US Department of Energy 2001).

This paper focuses on households that have both a gas furnace and a gas storage water heater. This market is projected to maintain its dominance into the future (US Department of Energy 2009a). Thus, new single-family construction represents a significant and important market for the introduction of higher energy-efficient gas space heating and water-heating technologies.

US gas space heating and gas water-heating technology characterization

Gas furnaces and water heaters are often distinguished by whether they use condensing or non-condensing technology. Gas non-condensing water heaters can be further distinguished between natural draft and power-vent technologies.

[3] Combined space heating and water heating appliances are integrated units that provide both space heating and domestic hot water and are not related to the furnace/water heater combinations evaluated in this study.

[4] Water heater fuel types in the single-family market segment are about the same as the national.

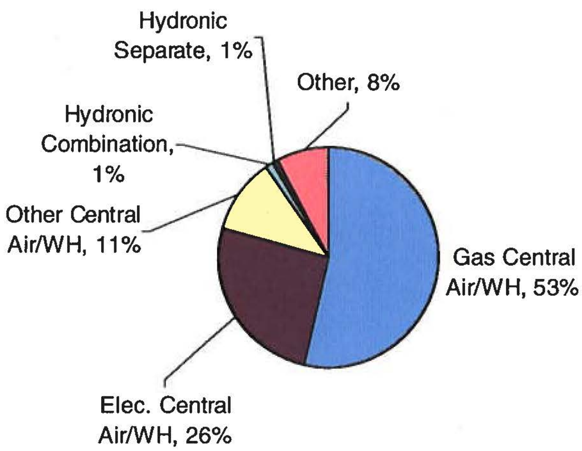


Fig. 1 US space heating and water-heating market for single-family households (built from 1980 to 2001, RECS 2001)

A typical non-condensing gas furnace has an efficiency rating of about 80% annual fuel utilization efficiency (AFUE), while a condensing furnace has an efficiency rating at or above 90% AFUE. In 2007, the most common furnace installed for replacement and in new construction[5] was a non-condensing gas furnace (approximately 63%; Air-Conditioning, Heating, and Refrigeration Institute 2008a).

The efficiency of water heaters, depending on the rated volume and other design considerations, ranges from 0.50 to 0.62 energy factor (EF) for non-condensing natural draft, from 0.60 to 0.70 EF for non-condensing power vent, and above 0.75 EF for condensing water heaters. In 2007, nearly all gas water heaters installed are non-condensing, with approximately 98% natural draft and 2% power-vent models (Air-Conditioning Heating and Refrigeration Institute 2008b). There are currently no shipments of residential condensing water heaters,[6] but there are prototype models available, and condensing water heaters are included in the current Energy Star program (Energy Star 2008).

The electricity and venting installation requirements are different for the various furnace and water-heater designs. Condensing and non-condensing furnaces as well as non-condensing power-vent water heaters and condensing water heaters require electricity to operate, while non-condensing natural-draft water heaters usually do not. Also, non-condensing natural-draft equipment is typically vented vertically through the roof, while condensing and non-condensing power-vent equipment is vented horizontally through the wall.

Figure 2 illustrates typical venting configurations. Identifying venting configurations is important because the venting system represents a significant fraction of the total installed cost and differs significantly for different furnace and water-heater combinations. Configuration D is the least expensive, since it uses plastic venting materials (compared to more expensive steel venting materials required in non-condensing furnaces and non-condensing natural-draft water heaters) and shorter vent lengths. Configuration A uses a single vent system for both appliances. Config-

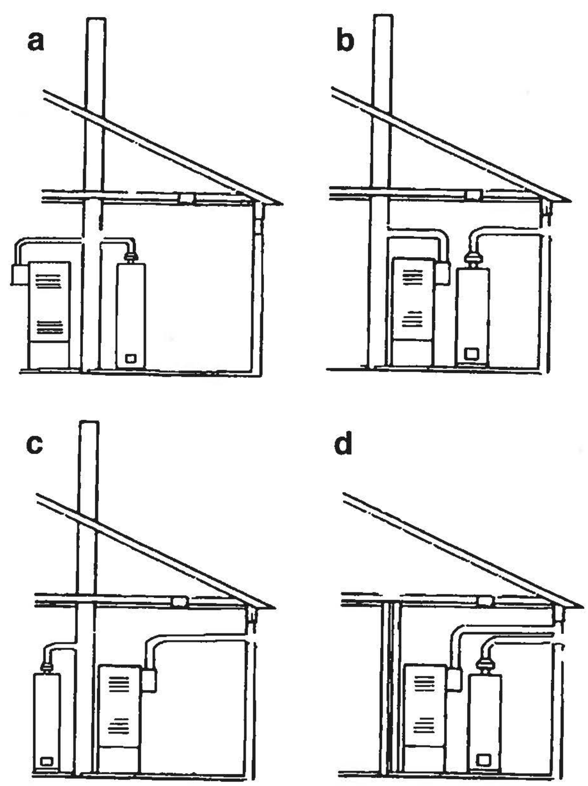


Fig. 2 Four gas furnace and gas water-heater venting configurations: **a** gas furnace and water heater vented through the roof, **b** gas furnace vented through the roof and gas water heater vented through the sidewall, **c** gas furnace vented through the sidewall and gas water heater vented through the roof, and **d** gas furnace and gas water heater vented through the sidewall

[5] Data on the share in new construction only are not available.
[6] There are some "non-residential" condensing models that are being used in residential applications (e.g., A.O. Smith's Vertex models).

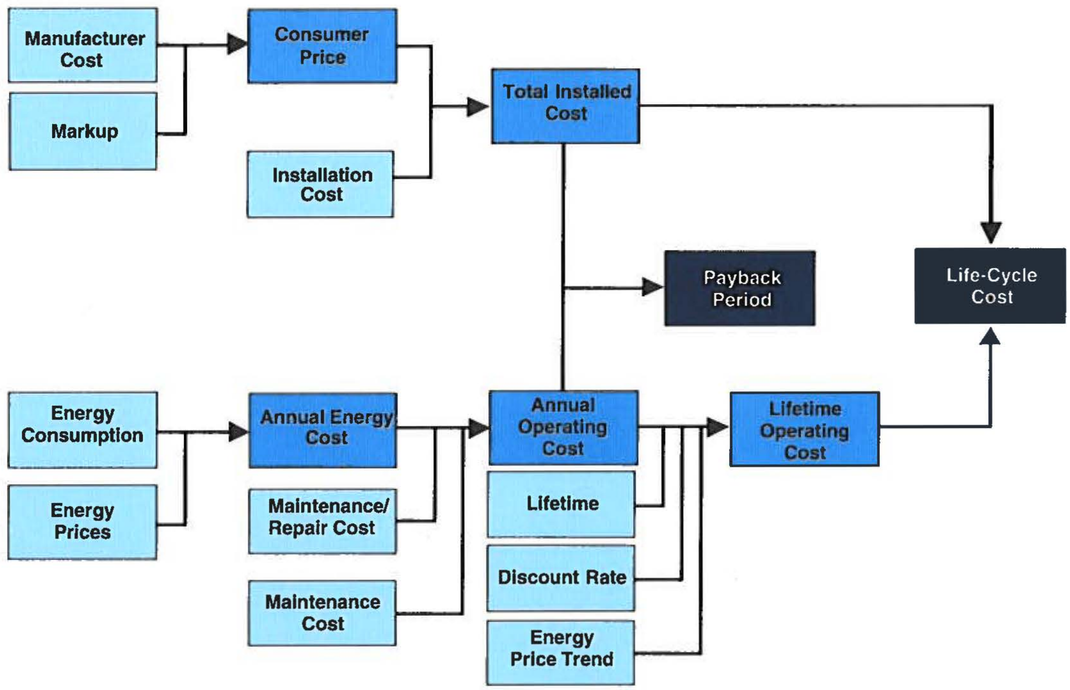


Fig. 3 Life-cycle cost analysis flowchart

urations B and C are the most expensive because of the need to apply two different venting types.

Methodology

This study assessed the energy savings and economics of the elected water-heater and furnace configurations installed in new homes. The LCC analysis addressed both the cost of buying and installing a furnace or water heater, and the operating costs summed over the lifetime of the equipment, discounted to the present. Figure 3 shows the LCC analysis components. The lighter-colored boxes represent the required inputs, the darker-colored boxes represent the values calculated by these inputs, and the darkest colored boxes show the analysis results. The total installed cost is the sum of the price to the consumer of the equipment and the cost to install the equipment. The operating cost takes in account the energy consumption of the furnace and the water heater and the price of energy as well as the repair and maintenance costs. The total installed cost and the operating cost are used to calculate the payback periods and the life-cycle cost of each of the selected water-heater and furnace options.

Table 3 Gas furnace and gas water-heater options

Option	Furnace type	Gas water-heater type (EF at 40 gallon rated volume[a])	Venting configurations
1	Non-condensing (80%)	Non-condensing natural draft (0.59)	Configuration a
2		Non-condensing power vent (0.64)	Configuration b
3		Condensing (0.80[a])	
4	Condensing (90%)	Non-condensing natural draft (0.59)	Configuration c
5		Non-condensing power vent (0.64)	Configuration d
6		Condensing (0.80[b])	

[a] Efficiency at 40-gal capacity tank. Efficiency varies with capacity

[b] Efficiency based on current Energy Star efficiency levels

Table 4 New construction households by region

Region labels	Census region	HDD criteria	Average number of single-family homes built with a gas furnace in 1999–2007[a]		Regional weights in national analysis (%)
			In thousands per year	%	
Region 1	Northeast	All	69.5	8.0	8.0
Region 2	Midwest	All	231.4	26.5	26.5
Region 3—cold	South	>3,000	278.8	31.9	20.4
Region 3—warm		<3,000			11.5
Region 4—cold	West	>3,000	293.6	33.6	16.3
Region 4—warm		<3,000			17.3
National totals			873.2	100.0	100

[a] US Department of Commerce 2008

To account for the uncertainty and variability of the inputs to the LCC analysis, we applied Monte Carlo[7] simulations, with many of the variables used in the calculations (e.g., discount rate, energy prices, and equipment lifetime) represented as distributions of values and with probabilities (weighting) attached to each value (Lutz et al. 2000). The LCC analysis estimated furnace and water-heater energy consumption under field conditions for a sample of households selected from the 2001 Residential Energy Consumption Survey (RECS 2001; US Department of Energy 2001). We selected those households having both a gas water heater and a gas furnace[8] and built in or after 1980.[9]

Table 3 shows the six gas furnace and water-heating options. These options are ordered first from non-condensing to condensing furnaces and then by increasing efficiency for water-heater design options. Overall, option 1 represents the least efficient furnace and water-heater combination, and option 6 represents the most efficient combination. The efficiency values used in the calculations were mostly based on commonly available models (US Department of Energy 2007). The fact that options 5 and 6 use venting configuration D is significant, since this configuration is the least expensive one.

To calculate the relative advantages and disadvantages of an option, we assessed the life-cycle cost savings and the payback period (PBP) by comparing option 1, which is the most common, to higher efficiency options (2–6). Option 1 serves as the reference to which the other options are compared.

In addition to a national LCC analysis, we performed a regional LCC analysis for the four US Census regions (US Department of Commerce 2009). The regional analysis accounts for significant energy use variations due to climate conditions (particularly for furnaces) as well as for regional differences in household characteristics, energy prices, and other variables. To account for climate differences within the regions, we divided Census regions 3 and 4 into warm and cold sub-regions (below and above 3,000 heating degree days (HDD)). To account for the differences in regional new construction trends, we calculated weights that represent the percentage of new single-family homes in each region (see Table 4). We assumed that these weights represent homes that are built with both a gas furnace and gas water heater, since almost all homes built with a gas furnace also have a gas water heater. The regional weights were then subdivided for regions 3 and 4 based on the number of households with gas furnace and water heater in RECS 2001.

The analysis considered the period from initial furnace and water-heater installation to the end of the lifetime of the furnace. Given the lifetime distributions for the water heater and the furnace, about 95% of the

[7] The Monte Carlo method utilizes computational algorithms that rely on repeated random sampling to compute results. In this study, the Monte Carlo analysis is performed using Crystal Ball, add-on software to MS Excel. The results are based on 10,000 samples per Monte Carlo simulation run.

[8] RECS does not distinguish between households that have weatherized gas furnaces (which are not included in this analysis) and non-weatherized gas furnaces.

[9] This is done to get a sample of households which approximates current new construction practices and allows us to generate a sufficiently large sample (447 household records representing 11.6 million households) for the analysis.

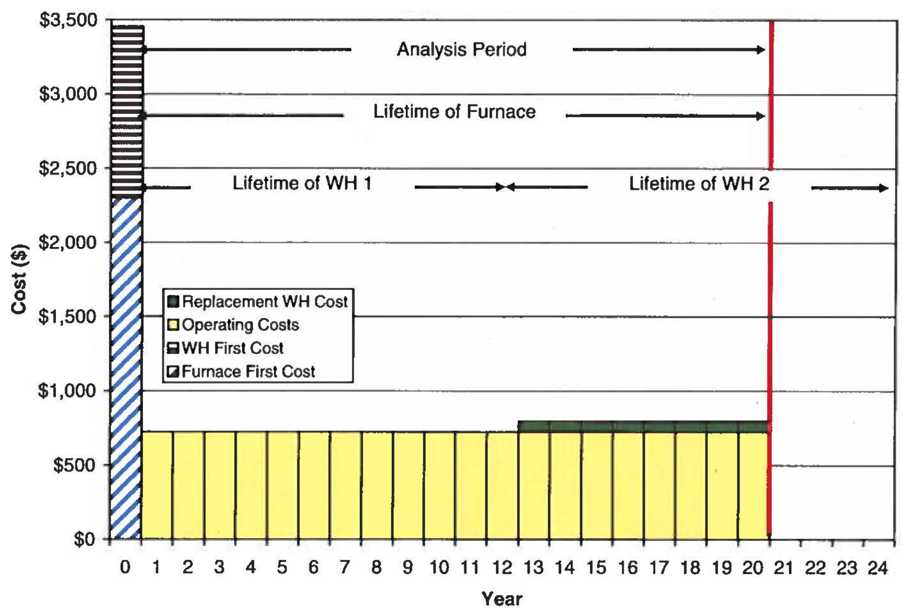


Fig. 4 Example of non-discounted components of life-cycle cost by year

time one or more additional water heater(s) would be installed during the lifetime of the furnace. In these cases, the total installed cost of the replacement water heater was added to the operating cost as an annualized expense from the time of the replacement to the end of the furnace lifetime. Figure 4 illustrates how this calculation is included in the overall LGC analysis. The example assumes that the furnace lifetime is 20 years, and the lifetime of the first water heater and the replacement water heater is 12 years. Therefore, the annualized expense for purchase and installation of the replacement water heater is one twelfth of the total installed cost.

For the NIA analysis we calculated the net energy savings (NES) and net present value (NPV) for gas furnaces and water heaters installed in new construction and shipped over a 20-year period (2010–2030) using the average LCC results for the installed cost, maintenance and repair cost, and the annual energy consumption. We measured the impacts of each option against a base case, which reflects the current market share[10] of the different furnace and water-heater combinations. This base case reflects the fact that many builders are already installing products at higher efficiencies (especially condensing furnaces). We modeled the annual shipments in new construction by using the projected number of housing units built and the market share of gas furnaces and water heaters installed in new homes. We also accounted for the useful service life of both appliances to estimate how long they are likely to remain in stock.

Analysis

LCC and PBP analysis

The total installed cost includes the consumer price and the installation cost, which includes labor, overhead, and any miscellaneous materials and parts. The operating cost included the energy expenditures and the repair and maintenance costs as well as the total installed cost of a replacement water heater. We discuss each of these inputs below.

Consumer price

US DOE research derives the consumer price based on manufacturer cost and contractor/builder and distribu-

[10] There are no disaggregated shipments data for new construction homes. We estimated the market shares in current installations based on 2007 Air-Conditioning, Heating, and Refrigeration Institute total shipments data (Air-Conditioning Heating and Refrigeration Institute 2008a, b). We then adjusted these shares to reflect the fact that a higher fraction of new homes is located in South and West regions, which have a lower penetration of condensing furnaces than the nation as a whole (US Department of Energy 2007).

Table 5 Consumer price by option for typical gas furnace and gas water heater (2007$)

Option	Furnace (75 kBtu/h)		Water heater (40 gal)		Total consumer price[a]
	Manufacturing costs	Average markups	Manufacturing costs	Average markups	
1	$413	3.37	$160	2.56	$1,803
2	$413	3.37	$276	2.34	$2,038
3	$413	3.37	$425	2.23	$2,340
4	$610	3.00	$160	2.56	$2,238
5	$610	3.00	$276	2.34	$2,473
6	$610	3.00	$425	2.23	$2,775

[a] Consumer prices in this table may not add up exactly to manufacturing cost multiplied by average markup due to rounding

Table 6 Installation costs for furnace and water-heater options (2007$)

Option	Venting installation configuration	Basic installation		Venting		Total
		Furnace	Water heater	Furnace	Water heater	
1	Configuration A	$451	$340	$829		$1,620
2	Configuration B	$451	$340	$443	$777	$2,011
3	Configuration B	$451	$347	$443	$777	$2,018
4	Configuration C	$453	$340	$777	$443	$2,013
5	Configuration D	$453	$340	$213	$213	$1,219
6	Configuration D	$453	$347	$213	$213	$1,226

Table 7 Average total installed costs furnace and water-heater options (2007$)

Option	Consumer price[a]	Installation cost	Total installed cost	Incremental total installed cost
1	$1,858	$1,620	$3,478	–
2	$2,098	$2,011	$4,109	$631
3	$2,397	$2,018	$4,415	$937
4	$2,314	$2,013	$4,327	$849
5	$2,554	$1,219	$3,773	$295
6	$2,853	$1,226	$4,079	$601

[a] Consumer prices in this table are averages over the range of furnace and water-heater capacities, not just the representative capacities in Table 5

Table 8 House heating load and hot water use by region

		Region 1 (Northeast)	Region 2 (Midwest)	Region 3 cold (South)	Region 3 warm (South)	Region 4 cold (West)	Region 4 warm (West)	National
House heating load, MMBtu/year	Avg	49.0	54.2	39.5	17.7	48.1	18.8	39.4
	Med	45.7	51.4	35.3	14.5	41.6	13.5	35.6
Hot water use, gal/day	Avg	40.4	51.5	53.2	58.5	53.3	56.1	52.9
	Med	38.0	47.2	48.6	53.8	49.8	51.5	48.6

Table 9 Gas furnace and gas water-heater component repair cost and lifetime

	Component	Component lifetime	Repair cost (2007$)	Applied to option
Gas furnace	Electronic ignition	10	$204	1, 2, 3, 4, 5, 6
	Blower motor	12	$297	1, 2, 3, 4, 5, 6
	Inducer motor	15	$297	1, 2, 3, 4, 5, 6
Gas water heater	Pilot light ignition	10	$162	1,4
	Electronic ignition	15	$204	2, 3, 5, 6
	Power vent	15	$297	2, 3, 5, 6

tor markups for the gas furnace and the gas water heater (US Department of Energy 2007, 2009a, b).[11,12] Manufacturer costs vary by rated volume for water heaters and by heating capacity and blower size for furnaces. The incremental cost of a power-vent water heater compared to a standard water heater includes the cost of additional components (blower and electronic ignition). The manufacturer cost of a condensing water heater includes the cost of changes to the heat exchanger and the tank. The analysis used contractor/builder and distributor markups to transform the manufacturer costs into a consumer price. The markup methodology assumes lower overall markup for higher efficiency equipment (condensing furnaces and water heaters and power-vent water heaters), because some distribution costs do not increase with increased efficiency.[13] Table 5 shows the manufacturer costs and the applicable markups for furnace and water heater at representative capacities as used to derive the consumer prices used in the LCC analysis.

Installation cost

The installation cost for each of the options is in Table 6. The installation cost values comes from US DOE research based on RSMeans cost estimates (US Department of Energy 2009b). The installation cost includes labor and materials for the gas furnace and water heater. The basic installation includes adding a gas line branch, water piping and condensate drain for water heaters and air-distribution connections and electrical components for furnaces, and the cost of locating and setting up the units. The only difference in basic installation cost between condensing and non-condensing equipment is the difference in cost of withdrawing the condensate via a horizontal plastic vent compared to withdrawing the exhaust via a vertical metal vent. We considered three different vent system installation costs: option 1 used a common vent through the roof; options 2, 3, and 4 used a combination of vertical metal vent and horizontal plastic vent; and options 5 and 6 used plastic vent.[14]

The total installed cost includes the consumer price and the installation costs and is presented as a distribution of values ("Appendix 2" and Fig. 12 of "Appendix 1"). Table 7 shows the average total installed costs from that distribution. The incremental total installed cost represents the difference between option 1 and each of the other options. Options 5 and 6, which feature a condensing furnace and power vent or condensing water heater, respectively, have the lowest incremental total installed costs because their lower installation costs partially offsets the higher consumer price.

Heating load and hot water use

Energy consumption for both the furnace and the water heater comes from calculations that used DOE test procedure parameters (see "Appendix 3"; Lutz et al. 1999, 2004). The house heating load (for furnaces) and the hot water use (for water heaters) used in the calculations vary for each sample household. Table 8 shows the house heating load and hot water use average and median values for the

[11] DOE's research used a reverse-engineering approach to obtain the manufacturer's costs.

[12] The consumer prices (particularly for residential furnaces as well as for condensing water heaters) are not commonly available. Space heating and water heating equipment are sold through several different distribution channels that have different price structures. To avoid these uncertainties we derived the consumer prices using the manufacturer cost and markup multipliers.

[13] The lower overall markup cost for higher efficiency equipment is explained in the US DOE 2006 Furnace and Boiler Rulemaking TSD (US Department of Energy 2007).

[14] Options 5 and 6 assume the equipment location is close to the wall to avoid long vent runs. In all cases, the water heater and furnace were assumed to be installed close to each other.

Table 10 Average energy use and operating costs (2007$)

Option	Annual gas use MMBtu/year	Annual elec use kWh/year	Annual maintenance/ repair cost[a] $/year	Avg operating cost $	Avg operating cost savings $
1	64.89	433	$178	$14,917	–
2	63.06	503	$202	$14,802	$116
3	59.47	493	$227	$14,195	$722
4	59.86	369	$178	$13,869	$1,049
5	58.03	438	$202	$13,753	$1,164
6	54.45	428	$227	$13,146	$1,771

[a] Including water-heater replacement if applicable

household sample by region (the resulting distribution of values is shown in Figs. 13 and 14 of "Appendix 2"). The national average hot water use (57.9 gal) is higher than the average value for gas water heaters (49.9 gal) reported in the DOE water-heater study (US Department of Energy 2005) because the household sample for new construction includes only RECS households built from 1980 to 2001 and not the entire stock. The new construction sample weights more toward warmer regions, and the number of occupants per household is higher than the national average.

Operating costs

The operating costs represent the costs paid by the consumer to operate and maintain or repair the furnace and the water heater over the lifetime of the equipment. The operating cost uses inputs from household energy consumption and energy prices. Average monthly energy prices were determined separately for the nine Census divisions and four large states based on 2006 EIA data, historical monthly EIA data, and 2006 US Census Bureau population estimates (US Department of Energy 2005, 2006a, b; US Department of Commerce 2006). The derived energy prices were matched to each individual household depending on its location. To arrive at prices in future years, we multiplied the 2006 average prices by the forecast of annual average price changes in AEO2009 (US Department of Energy 2009a). "Appendix 1" provides more details about the energy prices used in the analysis.

Table 11 Furnace and water-heater lifetime

Product class	Minimum	Average	Maximum
Gas water heater	6	12	18
Gas furnace	10	20	30

The furnace maintenance cost accounts for regular maintenance, while no maintenance cost was associated with the water heaters. The analysis assumed that certain components of both furnaces and water heaters might be repaired during the lifetime of the equipment (e.g., ignition device, blower motor, and power vent; US Department of Energy 2009b).[15] Table 9 lists the repair cost of key components as used in the analysis.

The operating cost accounts for the household annual energy consumption as well as for the maintenance and repair and is expressed as a distribution of values (Fig. 15 of "Appendix 2"). Table 10 shows the average energy use and operating cost for the analyzed household sample. The operating cost savings reflect the difference between option 1 and each of the other options. Option 6 has the lowest average operating cost and the highest annual fuel savings.

Condensing water heaters on average show more fuel savings than condensing furnaces. This is due to the higher efficiency difference between non-condensing and condensing water heaters (about 37%) compared to the difference between non-condensing and condensing furnaces (about 13%).

Discount rate

The LCC analysis discounted future operating costs to 2010 and summed them over the lifetime of the furnace. The discount rate used reflects after-tax real mortgage rates and on average equals 3.2% (US Department of Energy 2007).

[15] In the LCC analysis both the lifetime of the equipment and the component lifetime are presented as distributions. Therefore only households that have longer equipment lifetime encounter repair costs.

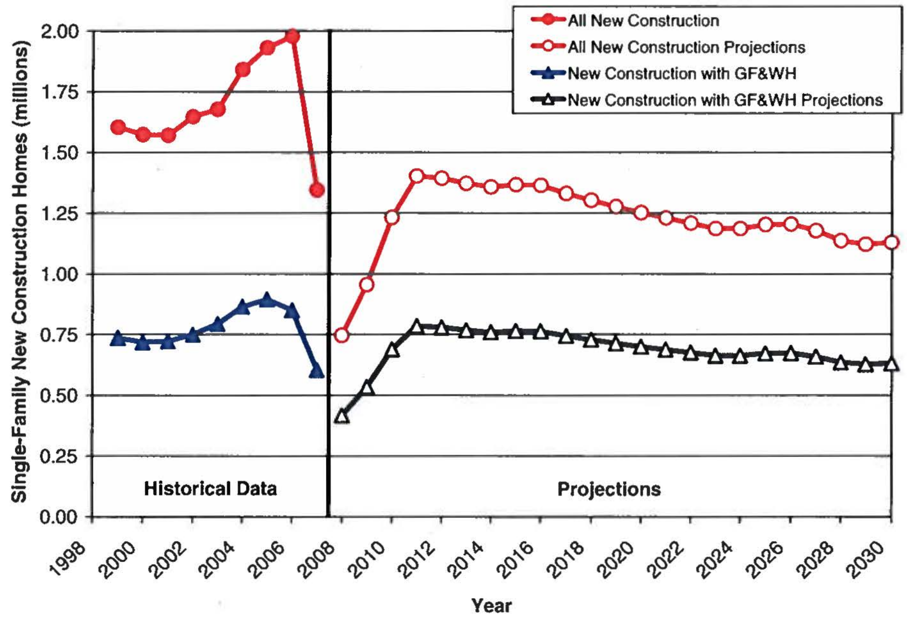


Fig. 5 New construction shipments (historical from 1999 to 2007 and projected from 2008 to 2030)

Lifetime

Lifetime estimates for furnaces and water heaters are shown in Table 11 (US Department of Energy 2007, 2008). In the analysis, lifetime is represented as a triangular probability distribution. The analysis uses the same lifetime for all furnace and water-heater designs.

National impacts analysis

The primary input parameters used in the NIA are discount rate, lifetime and energy prices along with the unit price, energy use and installation, and repair costs from the LCC analysis. Figure 5 shows the projected new construction shipments of gas furnace and water heaters in 2010–2030, which is based on new housing completion projections from the 2008 Annual Energy Outlook (AEO 2008; US Department of Energy 2008). The estimated average fraction of new housing completions with gas furnaces and gas water heaters is 49.5% based on US Census data (Table 2) and data from the 2005 American Housing Survey (US Department of Commerce 2005).

The NIA calculates national energy savings at the site level and then uses conversion factors from AEO 2008 to convert to primary energy use.[16] NIA also includes the impact of the rebound effect (also called a take-back effect or offsetting behavior), which refers to increased energy consumption resulting from actions that increase energy efficiency and reduce consumer costs.[17] To account for the rebound effect, national energy savings are reduced 10% for water heaters and 15% for furnaces (US Department of Energy 2007, 2009b).

Table 12 Average LCC and LCC savings (2007$)

Option	Total installed cost	Operating cost	Total LCC	LCC savings
1	$3,478	$14,917	$18,395	–
2	$4,109	$14,802	$18,911	($516)
3	$4,415	$14,195	$18,610	($215)
4	$4,327	$13,869	$18,196	$199
5	$3,773	$13,753	$17,526	$869
6	$4,079	$13,146	$17,225	$1,170

Negative savings within parentheses

[16] Site energy is the amount of heat and electricity consumed on site by a building as reflected in utility bills. Primary energy is the raw fuel that is burned to create heat and electricity, such as fuel used to generate electricity at a power plant, plus other losses in producing and transporting the fuel and electricity.

[17] The logic behind the rebound effect is that more energy-efficient products lower the marginal cost of the end-use service relative to lower energy-efficient products so consumers take some of the energy savings back in increased comfort or service.

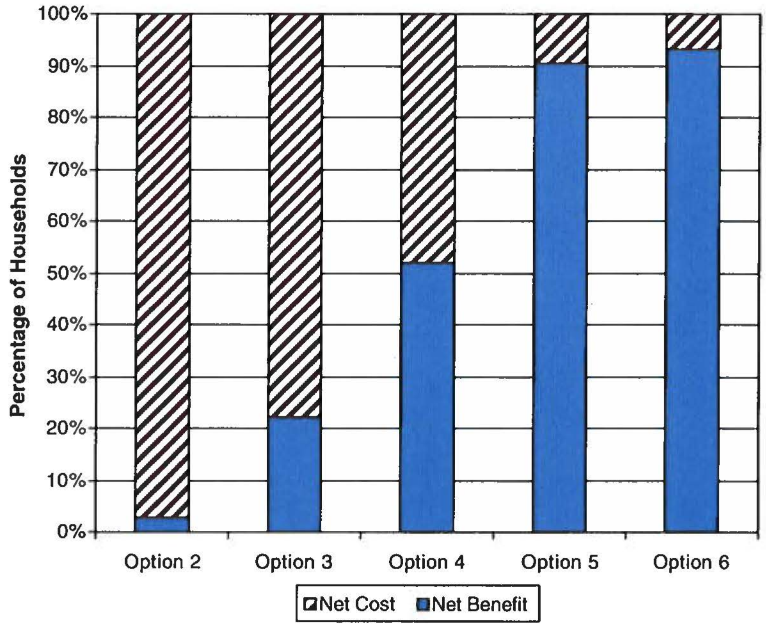


Fig. 6 LCC impacts for US new construction households

Results

Table 12 shows the average total installed cost, operating cost, total LCC, and average LCC savings for the six options (the distribution of LCC savings is in Fig. 16 of "Appendix 2"). Option 6 has the highest LCC savings ($1,170), followed by option 5 ($869). Options 2 and 3 have negative LCC savings or increased costs.

Figure 6 shows the percentage of all US new construction households that would experience a positive LCC savings (net benefit) or negative LCC savings (net cost) compared to option 1 if they were to install a combination of gas furnace and water heater as in options 2–6. All options with a condensing furnace (options 4–6) have net benefits for more than half of the households (52% for option 4, 90% for option 5, and 93% for option 6), while

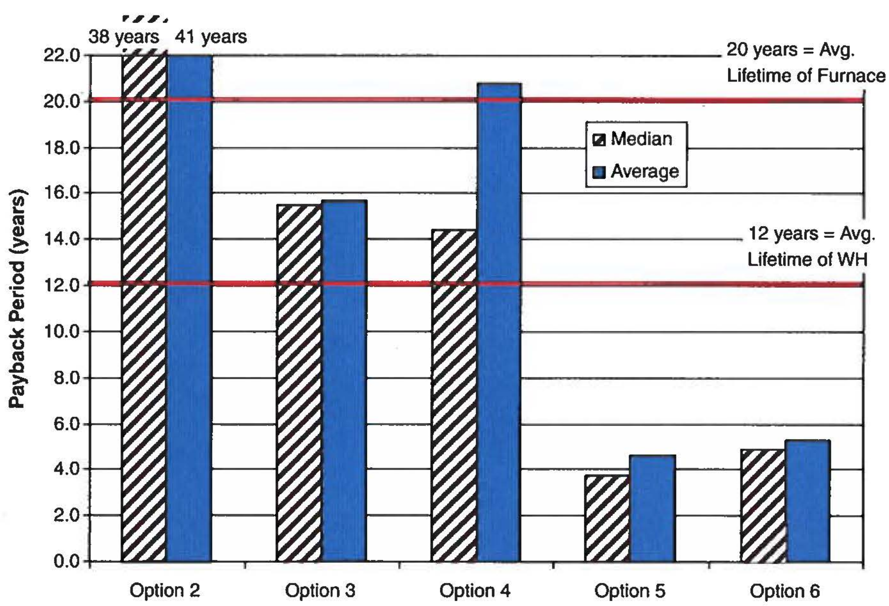


Fig. 7 Median and average household PBP

Table 13 Average LCC savings by region (2007$)

Option	Region 1 (Northeast)	Region 2 (Midwest)	Region 3 cold (South)	Region 3 warm (South)	Region 4 cold (West)	Region 4 warm (West)
1	–	–	–	–	–	–
2	($494)	($514)	($472)	($524)	($452)	($632)
3	($197)	($241)	($121)	($260)	$10	($473)
4	$611	$468	$198	($394)	$548	($323)
5	$1,302	$1,140	$912	$268	$1,281	$230
6	$1,599	$1,413	$1,263	$532	$1,743	$390

Values in parentheses indicate negative numbers

options 2 and 3 have net benefits for less than 50% of households (3% for option 2 and 22% for option 3).

Figure 7 shows the median and average payback period relative to option 1. Options 5 and 6 have the lowest payback periods (median payback period of 3.8 and 4.9 years, respectively). Options 3 and 4 have median paybacks of about 14–15 years, while option 2 has median and average payback beyond the lifetime of the equipment.

Table 13 shows the average LCC savings by region. The LCC savings vary by region because of the significant variations of the furnace heating load due to climate differences and regional energy prices. Option 6 shows the highest LCC savings for all regions. For regions above 3,000 HDD (regions 1, 2, and 3—cold; 4—cold), which account for about two thirds of the new construction homes, the average LCC savings for option 6 are between $1,263 and $1,743. The average LCC savings drop to $390 to $532 for the regions below 3,000 HDD (about one third of new construction households). Option 5 is also cost-effective in all regions. In general, option 4 shows savings in cold climates, but not in warm regions. Options 2 and 3 are generally not cost-effective (except option 3 in region 4—cold).

Table 14 shows the payback period by region for all options. In general, options 6 and 5 have median payback periods less than 8 years in all regions and less than 5 years in regions above 3,000 HDD. Options 3 and 4 offer median paybacks between 10 and 16 years in regions above 3,000 HDD, but median paybacks rise in regions below 3,000 HDD to 15 to 19 for option 3 and above the lifetime for option 4. Option 2 has median and average paybacks beyond the lifetime of either equipment in all regions.

The most cost-effective option (i.e., the lowest total LCC) for each household in each region is shown in Fig. 8. Option 6 has the lowest total LCC for 83% of all households, except for region 4—warm, where this fraction is approximately 65%.

Condensing water heaters, included in options 3 and 6, are not yet available for residential storage-tank applications. Figure 9 shows the most cost-effective for each household in wach region, excluding condensing waster heaters (i.e., options 3 and 6). Option 5, which combines condensing furnace and power-vent

Table 14 Payback period by region (years)

Option	Region 1 (Northeast)		Region 2 (Midwest)		Region 3 cold (West)		Region 3 warm (West)		Region 4 cold (South)		Region 4 warm (South)	
	Avg	Med	Avg	Med	Avg	Med	Avg	Med	Avg	Med	Avg	Med
1	–	–	–	–	–	–	–	–	–	–	–	–
2	34	34	39	39	34	33	35	42	32	33	64	63
3	14	14	16	16	15	15	15	16	13	13	19	19
4	10	11	11	12	14	16	35	43	12	12	36	37
5	2.8	2.9	3.2	3.4	3.7	3.9	6.8	7.2	2.9	3.1	7.8	7.9
6	4.0	4.0	4.4	4.5	4.8	4.8	6.9	7.0	3.9	4.0	7.6	7.7

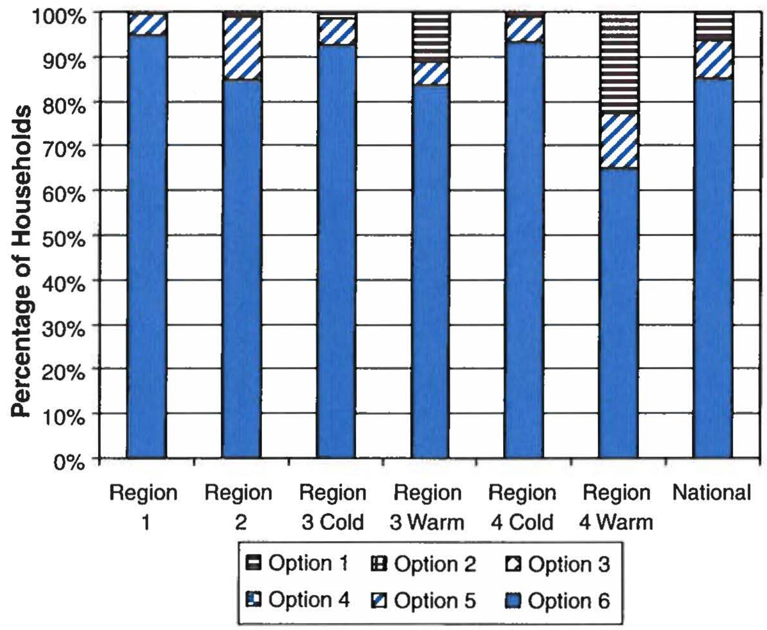


Fig. 8 Options with lowest total LCC by region

water heater, is the option with the lowest LCC for more than 90% of the households nationally and more than 95% of the households in all regions except regions 3—warm and 4—warm. Power-vent technology is readily available and currently maintains about a 2% share of the gas water-heater market.

The NES and NPV results for the six options are shown in Fig. 10. For the nation, option 6 has the highest NES (1.5 quads) and NPV ($8.0 billion) over the 2010–2030 period. Option 5 also has positive NES (0.7 quads) and NPV ($5.0 billion). Option 4 has a positive NES (0.6 quads) and NPV ($0.1 billion). Options 2 and 3 have positive NES results, but negative NPV results. The positive NPV for options 5 and 6 reflects their lower installation cost compared to options 2, 3, and 4 and their higher operating cost savings.

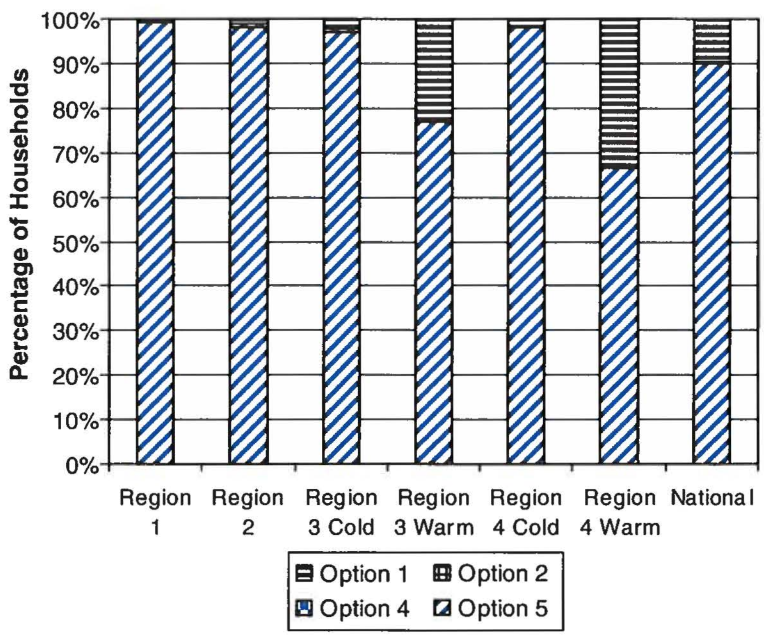


Fig. 9 Options with lowest total LCC (excluding condensing water heaters)

Conclusion

For the US single-family housing market the dominant combination of water heating and space heating is a gas furnace with a gas water heater. The results for the new construction segment of the single-family market show that options 4, 5, and 6 (condensing furnace with any type of water heating) show positive LCC savings. The LCC savings are very significant for options 5 and 6, which combine a condensing furnace with either a power-vent or condensing water heater. Over 90% of the natural-gas-using new single-family homes in the US would benefit from installing either options 5 or 6. These two options also have the lowest average payback (3.8 years for option 5 and 4.8 years for option 6). In all US regions, options 5 and 6 have the highest average LCC savings and the lowest average payback.

Option 6 is the most cost-effective technology (with lowest LCC) for 83% of all US households. Option 6 also has the lowest LCC for 80% or more of households in all regions, except for region 4—warm, where this fraction is about 65%. Option 5 is the second most cost-effective technology. Option 5 is attractive because it uses the power-vent water-heater technology, which already has about 2% market share.

The national impact analysis shows that both options 5 and 6 have significant potential national energy savings and economic benefits over the 2010 to 2030 period. In particular, option 6 shows very large NPV greater than $8 billion due to lower installation costs and higher operating cost savings. Together these more than offset the higher consumer price for the equipment.

Presently, in the new construction market, the choice of furnace and water-heater type is primarily driven by

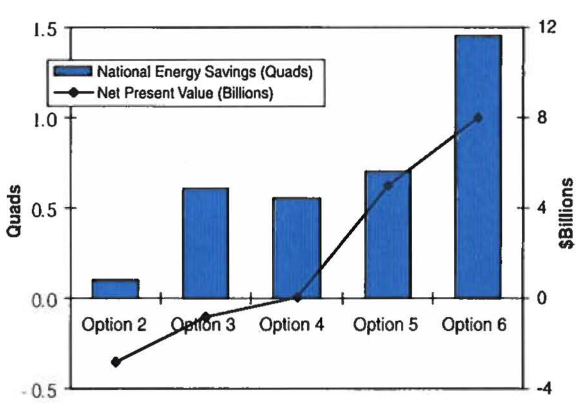


Fig. 10 NES and NPV results

first cost considerations and limited availability of power-vent and condensing storage-tank water heaters. This study suggests that homebuyers in most of the US would benefit from the installation of higher efficiency space and water-heating technologies. It also shows that important benefits may be overlooked when policy analysts evaluate the impact of space and water-heating equipment separately.

The economic results indicate that significant energy savings and consumer benefits may result from large-scale introduction of condensing or power-vent water heaters combined with condensing furnaces in US residential new construction.

Future work

The study was limited by factors that could be addressed in future research. Some of the potential future directions are as follows:

- Broaden the study to cover replacement situations as well as other residential building types (i.e., multifamily and mobile home).
- Broaden the scope to include gas tankless water heaters, variable-fire condensing tankless combined space/water heaters, solar water heaters, combined solar space/water heater, electric water heaters and furnaces, which include heat pump designs, and combination appliances.[18]

Acknowledgments The authors would like to thank Steven Meyers (LBNL), Jim Lutz (LBNL), and Lisa Thompson (LBNL) for providing valuable inputs and reviewing the paper.

Appendix 1: Energy prices

The energy use of furnaces and to a lesser extent water heaters varies by month. In general, US monthly energy prices also vary significantly by month. To more accurately capture the annual energy cost used by the

[18] Shipments of tankless water heaters are increasing significantly and are projected to be around 25% of the gas water heating market by 2015. DOE also projects a larger market for heat pump water heaters (US Department of Energy 2009b)

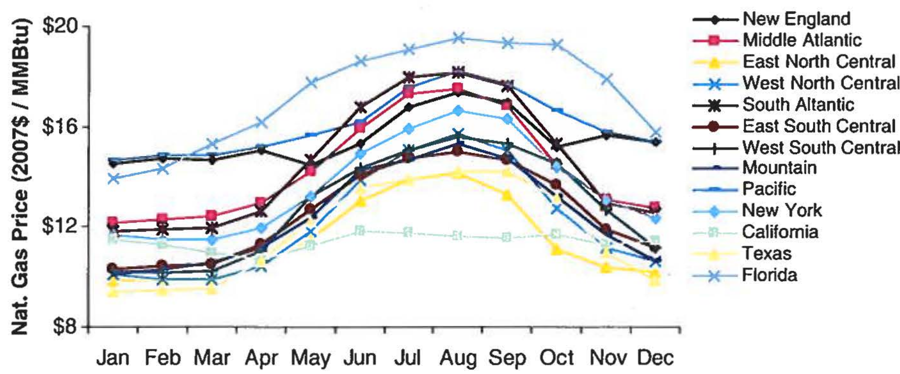


Fig. 11 Natural gas price forecast for 2010

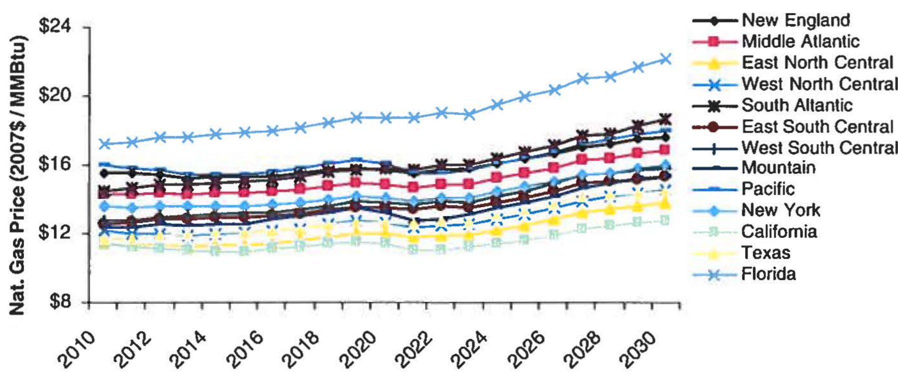


Fig. 12 Natural gas price forecast from 2010 to 2030

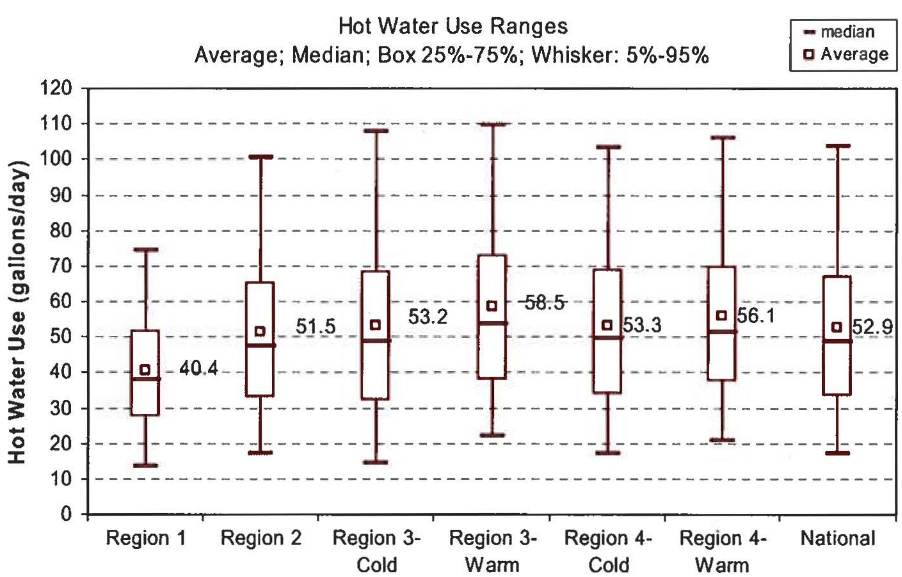
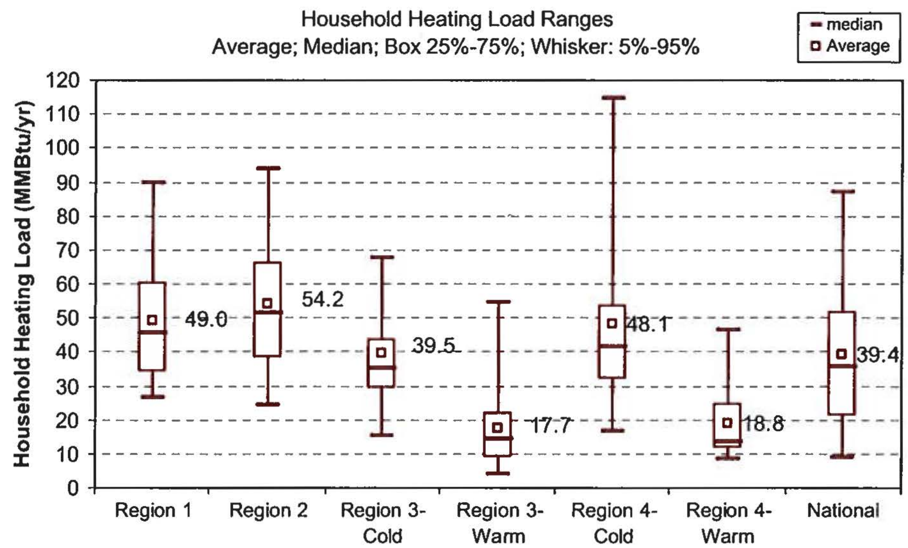


Fig. 13 Total installed price by option box plot

Fig. 14 Household heating load by region box plot



households, this analysis uses regional monthly energy prices instead of annual average energy prices.

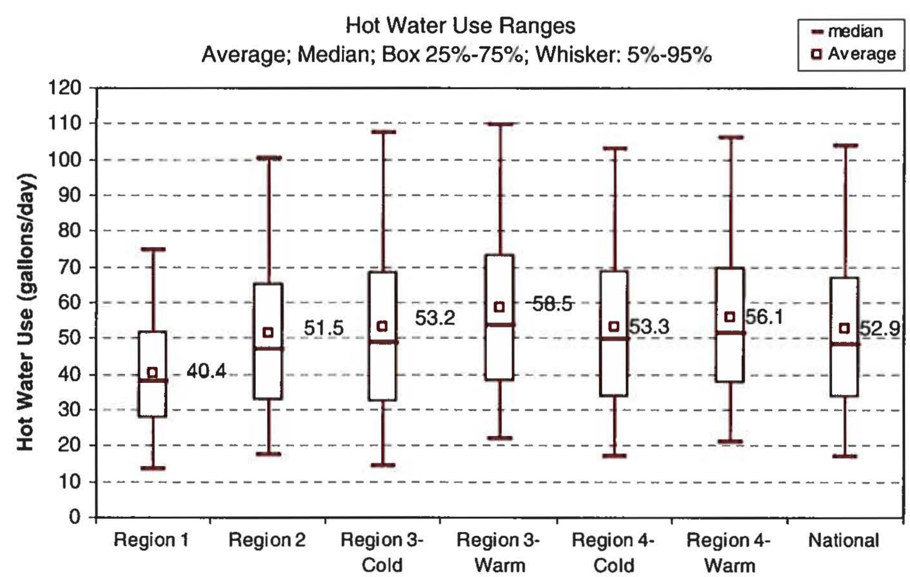
The regional monthly energy prices are derived from historical monthly energy prices (US Department of Energy 2005, 2006a, b; US Department of Commerce 2005) and projected into the future using AEO 2009 annual regional energy price projections (US Department of Energy 2009b). As an example, Fig. 11 shows the monthly natural gas price forecast for 2010 for the nine Census Divisions and four large states. Using monthly prices results in lower operating costs, because most consumption occurs in the winter when the natural gas prices are lower compared to the average annual prices.

Figure 12 shows annual trends (based on AEO 2009 projections) for all Census Division and four large states for the period (2010–2030).

Appendix 2: Distribution of results

The outcome of the LCC analysis is a distribution of values from a sample size of 10,000 households. The following charts (Figs. 13, 14, 15, 16, and 17) show

Fig. 15 Hot water use by region box plot



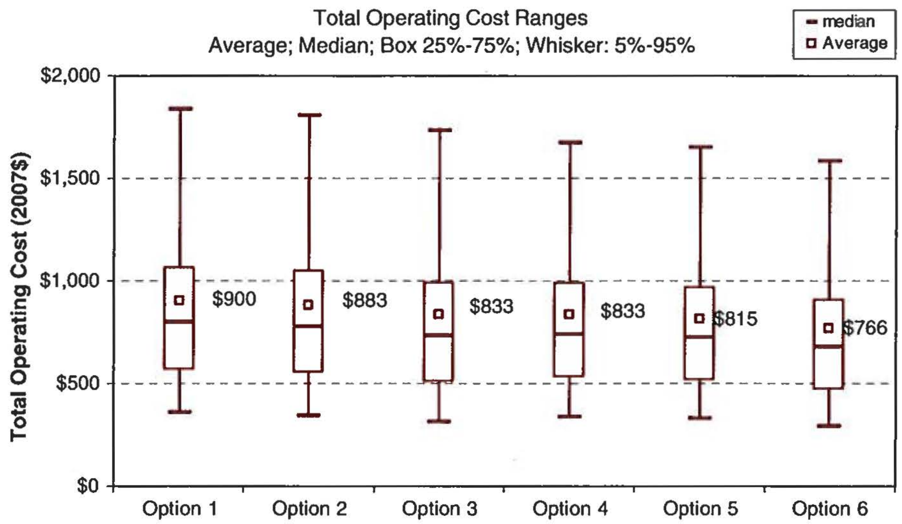


Fig. 16 Total operating cost by option box plot

the resulting distributions for the total installed cost, total operating cost and the LCC savings (by option), and for the house heating load and hot water use (regionally and nationally).

Appendix 3: Energy use calculations

This appendix offers an overview of the equations used to calculate energy use for gas water heaters and gas furnaces (Lutz et al. 1999, 2004).

The Water Heater Analysis Model (WHAM) method (Lutz et al. 1999) is used to derive the average daily water-heater energy consumption (Q_{in}):

$$Q_{\text{in}} = \frac{\text{vol} \times \text{den} \times C_{\text{P}} \times (T_{\text{tank}} - T_{\text{in}})}{\text{RE}} \times \left(1 - \frac{\text{UA} \times (T_{\text{tank}} - T_{\text{amb}})}{P_{\text{on}}}\right) + 24 \times \text{UA} \times (T_{\text{tank}} - T_{\text{amb}})$$

where

C_{p} specific heat of stored water, set constant at 1.000743 Btu/lb°F

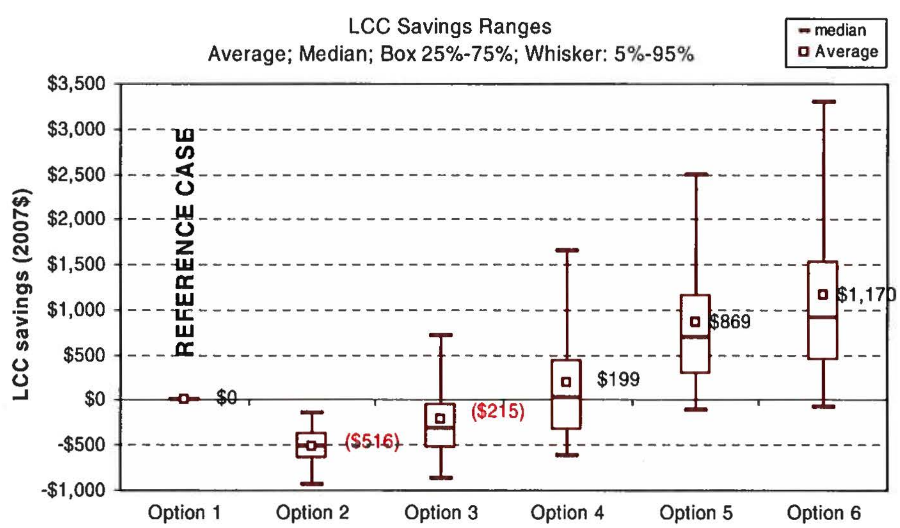


Fig. 17 LCC savings by option box plot (negative savings within parentheses)

den density of stored water, set constant at 8.29 lb/gal
P_{on} rated input power, Btu/h
Q_{in} total water-heater energy consumption, Btu/day
RE recovery efficiency, %
T_{amb} temperature of the air surrounding the water heater, °F
T_{in} inlet water temperature, °F
T_{tank} thermostat set-point temperature, °F
vol volume of hot water drawn in 24 h, gal/day
UA standby heat-loss coefficient, Btu/h°F

The volume of hot water drawn in 24 h is determined using a hot water draw model, which uses a set of household characteristics and water-heater performance parameters (US Department of Energy 2009b). WHAM yields total water-heater energy consumption (Q_{in}), which is disaggregated into electricity and fuel consumption.

The gas furnace fuel consumption (FuelUse) is calculated using:

$$\text{FuelUse} = \text{BOH}_{SS} \times Q_{IN}$$

where

BOH_{SS} steady-state burner operating hours (h)
Q_{IN} input capacity of existing furnace (kBtu/h)

The burner operating hours (BOH_{SS}) for each household are determined using the RECS' household energy use and the performance characteristics of the gas furnace.

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Deployment Map

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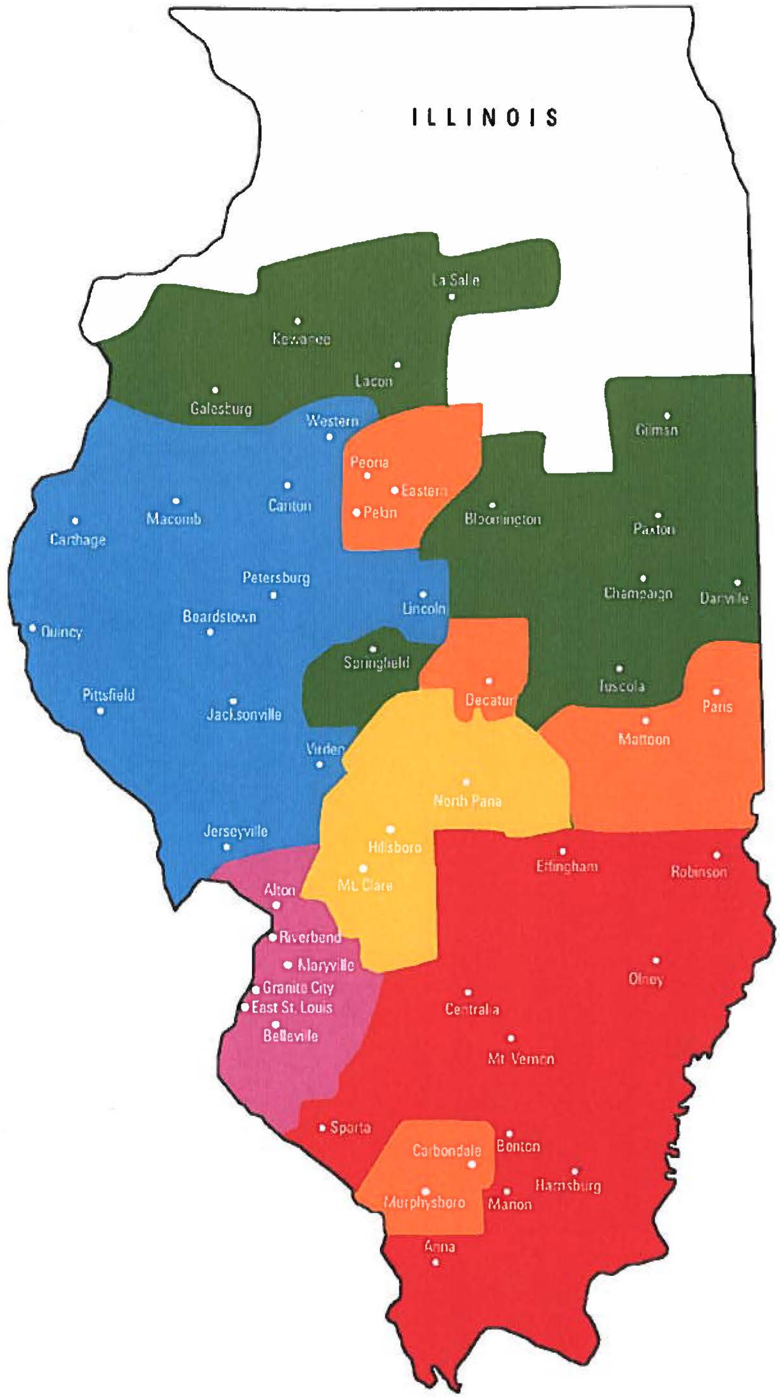
Percent of Total Upgrades by Year



	2014	2015	2016	2017	2018	2019
Electric	4%	17%	31%	56%	80%	100%

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ATTORNEY GENERAL
EXHIBIT 8

Annual Deployment by Meter

Year	Approved AMI Plan	100% Deployment
2014	40,419	46,972*
2015	148,000	161,567*
2016	148,000	179,000
2017	148,000	305,800
2018	148,000	305,800
2019	148,000	250,200
Total	780,419	1,249,339

*Actual Deployed Electric Meters

Operating Center	Division	Deployment Sequence	# of Electric Meters
2014			
Hillsboro	5	1	40,419
North Pana	4	2	6,553
2014 Total			46,972
2015			
North Pana	4		13,814
Effingham	4	3	14,121
Robinson	4	4	13,461
Olney	4	5	13,158
Centralia	6	6	16,719
Mount Vernon	6	7	21,886
Benton	6	8	17,856
Harrisburg	6	9	9,378
Marion	6	10	27,558
Anna	6	11	10,579
Sparta	6	12	8,576
Jerseyville	2	13	3,317
Incomplete Exchanges			(8,856)
2015 Total			161,567
2016			
Sparta	6		16,500
Jerseyville	2		12,400
Virden	2	14	11,500
Pittsfield	2	15	5,900
Quincy	2	16	26,900
Jacksonville	2	17	13,400
Petersburg	2	18	10,800
Beardstown	2	19	13,700
Carthage	2	20	8,200
Macomb	2	21	11,300
Canton	2	22	11,600
Lincoln CILCO	3	23	17,200
Western	1	24	10,700
Carryover from 2015			8,900
2016 Total			179,000

Operating Center	Division	Deployment Sequence	# of Electric Meters
2017			
Western	1		2,000
Lacon	1	25	16,500
Galesburg	1	26	44,000
Kewanee	1	27	15,200
LaSalle	1	28	37,800
Gilman	4	29	14,100
Paxton	4	30	15,600
Tuscola	4	31	14,100
Tuscola CILCO	4	32	9,000
Springfld CILCO	3	33	13,500
Champaign	4	34	83,400
Danville	4	35	32,200
Bloomington	3	36	12,400
Forecasted Incomplete Exchanges			(4,000)
2017 Total			305,800
2018			
Bloomington	3		49,900
Eastern	1	37	32,100
Pekin	1	38	25,000
Peoria	1	39	93,000
Decatur	3	40	63,500
Mattoon	4	41	21,300
Paris	4	42	8,600
Carbondale	6	43	16,400
Forecasted Incomplete Exchanges			(4,000)
2018 Total			305,800
2019			
Carbondale	6		4,500
East St. Louis	5	44	33,600
E St Louis - IP	5	45	200
Belleville	6	46	90,900
Maryville	5	47	46,000
Granite City	6	48	22,100
River Bend	5	49	17,700
Alton	5	50	27,200
Finish All Incomplete Meter Exchanges			8,000
2019 Total			250,200
6 Year Total (2014-2019)			1,249,339

Ameren
ILLINOIS

Advanced Metering Infrastructure (AMI)

Cost / Benefit Analysis

May 2016

Table of Contents

1. Executive Summary

To develop the cost/benefit analysis for the AMI deployment, Ameren Illinois used the guiding principles outlined in Section 16-108.6(a) of the Illinois Public Utilities Act which provides as follows:

> "Cost beneficial" means a determination that the benefits of a participating utility's Smart Grid AMI Deployment Plan exceed the costs of the Smart Grid AMI Deployment plan as initially filed with the Commission or as subsequently modified by the Commission. This standard is met if the present value of the total benefits of the Smart Grid AMI Deployment Plan exceeds the present value of the total costs of the Smart Grid AMI Deployment Plan. The total cost shall include all utility costs reasonably associated with the Smart Grid AMI Deployment Plan. The total benefits shall include the sum of avoided electricity costs, including avoided utility operational costs, avoided consumer power, capacity, and energy costs, and avoided societal costs associated with the production and consumption of electricity, as well as other societal benefits, including the greater integration of renewable and distributed power sources, reductions in the emissions of harmful pollutants and associated avoided health-related costs, other benefits associated with energy efficiency measures, demand-response activities, and the enabling of greater penetration of alternative fuel vehicles."

As support for the AMI Plan, Ameren Illinois developed a cost/benefit analysis of implementing AMI within the Ameren Illinois service territory and submitted this filing to the Illinois Commerce Commission (ICC) on March 30, 2012. In June 2012, after a ruling by the ICC on the initial filing, Ameren Illinois submitted a modified cost/benefit analysis, refocusing the base case to an 8 year, 62%, electric-only AMI meter deployment plan, adding additional benefits in key areas, and refining cost estimates. The Commission approved the modified AMI Plan in Docket No. 12-0244 in December 2012.

In April 2016, Ameren Illinois proposed an acceleration of its AMI deployment in its annual AMI Update to the ICC. The ICC directed Ameren Illinois to re-open its approved AMI Plan for review. In this filing, Ameren Illinois presents a cost/benefit analysis for an 8 year, 100% electric allocated AMI meter deployment. As demonstrated here, this further modified AMI Plan to deploy AMI to 100% of AIC's electric delivery customers remains cost beneficial.

Figure 1 summarizes the specific benefits of this implementation.

Figure 1: AMI Implementation Benefits Summary

Direct Operational Benefits

- Meter Reading Automation
- Operational Efficiencies in Field & Meter Services
- Reduction in Unaccounted for Energy
- Operational Efficiencies in Billing and Customer Management
- Improvement in Capital Spend Efficiency
- Improvement in Outage Management Efficiency

Quantified Customer/ Societal Benefits

- Enhanced Customer Service
- Billing Accuracy Improvement
- Reduced Consumption on Inactive Meters
- Informed Decisions on Energy Usage
- Reliability - Earlier Identification of Outages Prompts Accelerated Response
- Environmental Preservation through Reduced Peak-Time Usage

Additional Customer/ Societal Benefits

- Enables Net Metering and Reduces Costs
- Enables New Service (e.g. smart appliances, other load reduction programs)
- Potential to Enable PEVs (Plug-in Electric Vehicle)
- Enhanced Customer Convenience
- Increased Safety for Meter Readers and Field Services Personnel
- Job Boost to Local Economy
- Bolsters Market Competition - Beneficial for Customers

The table below summarizes the Internal Rates of Return (IRR) for the three different AMI meter deployment scenarios analyzed:

Table 1: AMI Deployment Internal Rates of Return

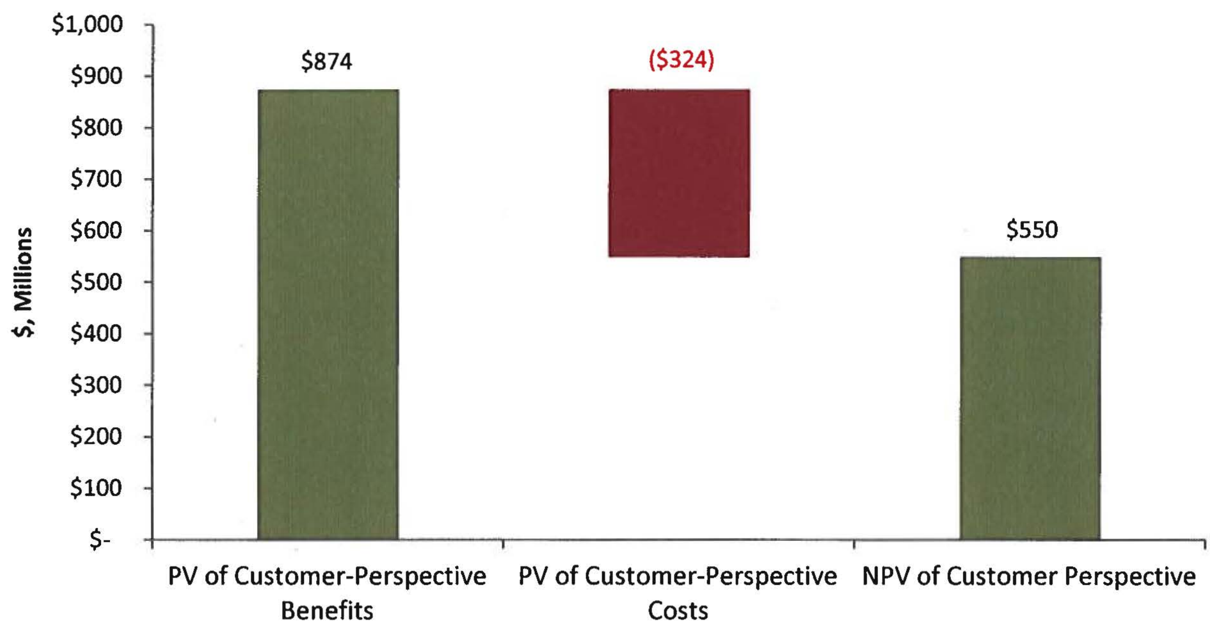
Deployment Scenario	IRR
62% Electric Only by 2019 (Approved by the ICC in December 2012)	14.6%
62% Electric Allocated by 2019 (Current Forecast)	22.4%
100% Electric Allocated by 2019	28.4%

Each scenario above significantly exceeds Ameren Illinois' current cost of capital of 5.58% with the most benefit accruing to customers from the 8 year, 100% AMI deployment. The allocated scenarios analyzed were updated from the original 8 year, 62% AMI meter deployment plan approved by the ICC with the following:

- Actual capital costs for 2012 through 2015 and updated capital expenditure forecasts for 2016 through 2031
- Allocated costs shared by gas and electric AMI based on ICC approved allocation factors
- Actual O&M benefits realized through an AMR meter read discount from 2014 through 2020
- Additional O&M costs for an AMR termination fee
- Scaled costs and benefits for 100% of customers receiving AMI.
- Revised model sensitivities to a tighter range now that Ameren Illinois has more experience with the AMI technology.

The following figure summarizes the present value of the benefits and costs of the 100% deployment of AMI in Ameren Illinois' service territory.

Figure 2: NPV of Ameren Illinois 100% AMI Business Case Summary



On the cost side, Ameren Illinois has incurred and will incur new costs for AMI meters and communications infrastructure, IT systems, implementation services, and on-going operational expenses. During the 20-year evaluation period, Ameren Illinois expects the Present Value total cost of ownership to reach $324 million.

The Present Value of benefits over the 20-year evaluation period is estimated at $874 million, and exceeds the Present Value of costs by $550 million. Benefits result from meter reading automation, reduction in unaccounted for energy, operational efficiencies in field & meter services, billing and customer management, improved distribution system spend efficiency, as well as customer benefits such as reduction in consumption on inactive meters, Demand Response benefits, etc. as listed in Figure 1. The Net Present Value calculation for the 100% electric AMI deployment was determined using Ameren Illinois' weighted average cost of capital (WACC) set in the 2015 formula rate update filing of 5.583% as the discount rate.

Ameren Illinois' 100% AMI meter deployment provides significantly more benefits to the electric customer than was originally proposed in the June 2012 AMI Plan.

2. Ameren Illinois AMI Context and Background

As a utility serving the State of Illinois, Ameren Illinois is a leading energy provider that serves more than 1,200 communities. Every day, Ameren Illinois delivers energy to approximately 1.25 million electric and 830,000 natural gas customers in central and southern Illinois. Ameren Illinois also was an early adopter of Automated Meter Reading (AMR), having introduced this technology to parts of the utility's 43,700-mile service territory in 1998. Upon completion of the automated meter deployment, Ameren Illinois had installed 678,000 electric and 476,000 gas one-way-communication-enabled AMR meters covering more than half of its gas and electric customers.

Taking advantage of advancements in metering technology and leveraging two-way radio frequency (RF) networks, Ameren Illinois strives to promote "green" technologies and ensure high-quality service in a cost-effective manner through the AMI initiative. As such, and in order to fulfill the provisions required as part of the AMI Plan, our AMI cost/benefit analysis evaluates a 20-year investment and outlines the determination that the benefits exceed all costs reasonably associated with this initiative.

A number of key assumptions were formed as Ameren Illinois analyzed variables and scenarios to identify impacts to customers from implementing AMI in its service territory. Additional detailed assumptions are contained in the Appendix.

2.1. Key Deployment Assumptions

2.1.1. Ownership/Operation of AMI Network

Ameren Illinois plans to own and operate the AMI communications network (as opposed to paying an outside vendor to own and/or operate the network).

2.1.2. Allocated Electric Base Case

For the purposes of this business case, it is assumed that AMI is implemented for the benefit of Ameren Illinois' electric and gas customers. Investments that are shared by both gas and electric AMI customers are allocated based on existing allocation methodologies approved by the ICC. The business case captures all costs specific to the electric customer (for instance, an electric meter) and the allocated portion of the shared costs (for instance, the AMI network equipment.)

2.1.3. Implementation Schedule

Ameren Illinois has revised its original deployment plan from an 8 year, 62% AMI deployment plan to an 8 year, 100% AMI deployment, ending in 2019.

2.1.4. Vendor Pricing

Ameren Illinois' successfully contracted with all of its major vendors for the program. Each contract contains the provisions for expansion to 100% electric AMI deployment. The major contracts for the AMI program include:

- AMI Meters, Network, and Deployment

- Meter Data Management System
- System Integration, Change Management, and Customer Communication
- Software Development Staffing
- Residential Web Presentation of Customer AMI Data
- Information Technology Hardware and Software
- Cloud Based AMI Data Analytics

2.1.5. Cost Estimates Approach

The Ameren Illinois AMI project team worked through formal RFI and RFP processes to engage with multiple external vendors and internal stakeholders to obtain vendor contracts and internal staffing forecasts to successfully deploy an AMI solution.. The team also engaged with internal IT, Customer Service, Field Operations, and Corporate Planning teams to assess the costs of integrating an AMI solution into Ameren Illinois' business processes. Moreover, department leaders helped identify resource requirements and cost estimates for program management and associated operational activities such as customer education, customer management, and technical support.

In 2013, Ameren Illinois successfully contracted with all of its major vendors for the AMI program. For this cost/benefit analysis, Ameren Illinois has included the costs as contracted.

With respect to meter depreciation, Ameren Illinois has reviewed some of the largest AMI deployment plans in the United States, such as those by Duke Energy, Southern California Edison, DTE, and PG&E to base its AMI deployment on a useful life of 20 years for the AMI meter. As with any complex system, individual components may fail early or last longer than the overall useful life. The AMI meter's useful life does not depend on when the first component fails or how long the last meter-module functions. Instead, its life depends on the system as a whole operating correctly and reliably. Moreover, Southern California Edison conducted product testing that concluded that the meter useful life would be 20 years or more[1].

2.1.6. Benefit Estimates Approach

The Ameren Illinois AMI project team relied heavily on both internal and external AMI and metering experts to identify AMI benefit areas and detail cost reductions and loss prevention associated with each benefit area commensurate with the meter deployment schedule. Direct operational and customer benefits in several areas such as meter reading, field and meter services, unaccounted for energy, billing accuracy, consumption on inactive meters, Demand Response, Energy Efficiency, and PEV were quantified. Ameren Illinois has also included numerous additional customer and societal benefits which were not quantified in the business case.

2.1.7. Cost/Benefit Analysis Approach

A rigorous approach to the AMI cost / benefit analysis was conducted by using several different evaluation methodologies, including Internal Rate of Return, Net Present Value (NPV) analysis, a Ratepayer Impact Test, as well as Total Resource Cost (TRC) analysis. The time horizon used for the business case was 20 years. A terminal value was also calculated to take into account the costs and benefits associated with the un-depreciated AMI infrastructure remaining beyond the 20 year period. The cost benefit analysis is taken from the customer perspective, with costs and benefits modeled as revenue requirement adjustments.

[1] SCE Cost Benefit Analysis, Vol 3., December 21, 2006

In Ameren Illinois' approved AMI Plan, the discount rate that was used for the NPV analysis reflected a customer-perspective discount rate. This is consistent with the Illinois Statewide Smart Grid Collaborative (ISSGC) recommendation of "using an appropriate discount rate." Therefore, a customer-relevant discount rate was used for this analysis as the 20-Year Treasury Bill rate (3.62% in 2012). This approach was consistent with the ComEd AMI pilot evaluation.

With the revision to the cost/benefit analysis expanding AMI to 100%, Ameren Illinois took a more conservative approach to the NPV analysis by using its current weighted average cost of capital of set in the 2015 formula rate update filing of 5.583% as the discount rate.

2.2. Alignment with Illinois Statewide Smart Grid Collaborative Recommendations

Ameren Illinois adhered to the guidelines of the Illinois Statewide Smart Grid Collaborative (ISSGC) when developing the cost and benefit estimates. The table below summarizes how Ameren Illinois complied with these guidelines.

Table 2: Alignment with ISSGC Cost-Benefit Filing Requirements

Requirement (from ISSGC report)	Sub-Requirement (from ISSGC report)	Ameren Illinois Business Case Alignment
1. Provide cost-benefit analyses of the investment(s), including a Total Resource Cost test:	The analysis should include any factor (i.e., cost or benefit) that meets the following criteria: • They can be expected to have a meaningful economic impact on the utility's investment decision or are relevant to the Commission's approval decisions • They can be reasonably and transparently quantified and monetized • They are relevant to the analysis, specifically including the costs of achieving claimed benefits.	✓ Requirement Met
	Costs and benefits should only be counted once; there can be no double-counting of benefits.	✓ Requirement Met
	All costs and benefits used in the analysis should be incremental to the investment when compared with a baseline or "business as usual" scenario. The baseline scenario should reflect the related costs or benefits that would be anticipated if the investment were not made.	✓ Requirement Met (Costs and benefits were analyzed to ensure only incremental values were used)
	The cost-benefit analysis should recognize as a separate line item any stranded costs that would result from the smart grid investment.	✓ Requirement Met

<table>
<tr><th>Requirement (from ISSGC report)</th><th>Sub-Requirement (from ISSGC report)</th><th>Ameren Illinois Business Case Alignment</th></tr>
<tr><td rowspan="4">1. Provide cost-benefit analyses of the investment(s), including a Total Resource Cost test:

(cont'd)</td><td>The utility should be required to present multiple views, or perspectives, as part of their cost-benefit analysis to be filed with the Commission.
• A Total Resource Cost perspective for investments should be presented by the utilities – both with societal costs and benefits and without societal costs and benefits
• Other perspectives that should be presented include a Ratepayer Impact view (depicting how rates would be impacted) and a Customer/Participant view (depicting the impacts of customer-specific costs and benefits)

As appropriate to each test, the cost-benefit analysis should separately identify:
1) Those costs and benefits that will be directly incurred or realized by ratepayers through the traditional ratemaking structure
2) Those costs that can be expected to be incurred by non-utility parties
3) Those benefits that will flow, if at all, through the wholesale price of energy or other markets
4) Those benefits associated with broader societal objectives or results that are not necessarily reflected in regulated customer rates.</td><td>✓ Requirement Met

(Both a customer/ratepayer impact and Total Resource Cost views are included in this analysis)</td></tr>
<tr><td>Cost-benefit analysis may bundle or package together investments in several applications if those applications are needed to function together or provide otherwise unachievable synergies, or if they are reliant on a common infrastructure investment.

To the extent that it is feasible to separate underlying platforms from individual applications, smart grid applications contained within a package should still be subject to individual cost-benefit analysis based on their stand-alone incremental costs and benefits.</td><td>✓ Requirement Met

(Ameren Illinois views the AMI investment as a comprehensive capability that is considered as a whole)</td></tr>
<tr><td>Cost-benefit analysis should provide a calculation of a payback period based on the present value of the annual cash flows of the smart grid investment or package</td><td>✓ Requirement Met</td></tr>
<tr><td>Potential non-regulated, third party, or incidental revenue from smart grid infrastructure investments should be reflected in the cost-benefit analysis.</td><td>N/A

(This analysis does not include non-regulated or third-party/incidental revenue)</td></tr>
</table>

Requirement (from ISSGC report)	Sub-Requirement (from ISSGC report)	Ameren Illinois Business Case Alignment
2. Provide documentation supporting the cost-benefit analyses	Documentation of key assumptions underlying the analyses, particularly of those factors that may have a high degree of variability and/or uncertainty	✓ Requirement Met
	Discussion of the uncertainties associated with estimates of costs and benefits over the term of the payback period	✓ Requirement Met (Included a sensitivity analysis – see section 7)
	Discussion of the potential change in benefits and costs that may occur over time assuming various implementation schedules	✓ Requirement Met
	Identification and discussion of other investments or approaches (if any) that reasonably might achieve similar or better results	N/A
	Documentation of the discount rates used in the analyses and a discussion of the rationale for their use	✓ Requirement Met
	Documentation of a sensitivity analysis of the projected costs and benefits of the investment to variables and assumptions. While reasonable discretion should be provided in terms of the variables and assumptions to be included, the sensitivity analysis should: – Identify the key variables from the cost-benefit analysis that merit sensitivity analysis. The degree of participation, assumed behavioral impacts, and persistence of customer behavior changes should be among the variables included in sensitivity analyses. Other candidates for inclusion are variables (such as emission costs and reliability) that have a wide range of potential values and/or are more subjective in nature. – Produce cost-benefit results using alternate values for the variables in order to demonstrate the sensitivity/impact various scenarios might have on the economic profile of the smart grid investments.	✓ Requirement Met
	Discussion of the rationale behind the packaging or bundling of applications in the analyses	✓ Requirement Met (Ameren Illinois views the AMI investment as a comprehensive capability that is considered as a whole)
	Documentation of the investment's useful life and the basis for its determination	✓ Requirement Met

Requirement (from ISSGC report)	Sub-Requirement (from ISSGC report)	Ameren Illinois Business Case Alignment
2. Provide documentation supporting the cost-benefit analyses (cont'd)	Documentation of the length of time over which reasonable customer benefits can be reliably estimated	✓ Requirement Met
	Documentation of assumptions regarding any environmental benefits incorporated in the analysis (e.g., emissions reduced, values of emissions/allowances)	✓ Requirement Met
	Discussion of the methodology and assumptions used in deriving the estimated benefits from load shape changes. This discussion should describe the model(s) used, model inputs and outputs, model logic (at a high level), scenarios performed, and how model results are to be interpreted.	✓ Requirement Met (This analysis includes a high-level summary of the Demand Response benefit methodology, which is based on peak load shifting)

3. Ameren Illinois AMI Program Costs

Ameren Illinois has conducted detailed cost assessments to determine the life cycle cost of AMI ownership, as well as the capital and operations and maintenance (O&M) costs associated with AMI deployment. AMI deployment to 100% is expected to be completed within 8 years. Operations of the AMI infrastructure will commence prior to the AMI system installation and continue through the timeframe of the business case.

The major cost components of the AMI deployment are summarized in the table below.

Table 3: Key Cost Components (in $ millions, over 20 years)

Key Cost Components	Total
Capital	
AMI Meters	$196
Communication Network	$29
Information Technology	$55
Program Management	$10
AMI Operations Support of Deployment	$23
Subtotal of Capital Expenditures	**$313**
O&M	
Meter Reading	$16
Information Technology	$115
Management and Other Costs	$76
Subtotal of O&M	**$207**
TOTAL OF CAPITAL AND O&M	**$520**

3.1. AMI Meters Capital

This cost category includes the capital costs associated with the installation and configuration of the AMI meters.

Ameren Illinois estimates that the 20-year capital costs incurred as a result of full AMI deployment within 8 years will be approximately $196 million. Below is a summary of the main components of these costs.

Table 4: AMI Meters Cost (in $ millions, over 20 years)

AMI Meters Cost Drivers	Capital
AMI Meters	$158
AMI Meter Installation	$38
TOTAL	**$196**

The costs were derived from the AMI vendor's contract that was signed in April 2013 which included provisions for Ameren Illinois' to extend to 100% of its service territory.

AMI meter costs include the costs for the physical AMI meter for single-phase and three-phase meters having embedded two-way RF radio communicators. All self-contained meters that are 200 Amps or less will also have an internal switch for remote connect / disconnect applications. Each meter also includes a capitalized software license cost for the AMI Head End and Meter Data Management Software applications. This cost is based on a 100% deployment over 8 years.

Installation of meters is a complex activity involving pre-installation preparations and field deployment. During pre-installation, facilities are prepared for AMI meter processing, field surveys are completed, and plans are developed for meter deployment.

Meter deployment is a major activity. It involves setting up cross-dock facilities as logistical hubs. Meters for electric services that are 200 amps or less are sample tested and meters for electric services greater than 320 amps are 100% tested for performance and accuracy before deployment. The meter installation workforce is trained and deployed to cross-dock facilities. Deployment is scheduled based on route plan. Meters are installed, and clean-up is performed to complete the installation process. Tests of meter communication and data accuracy are performed as a part of commissioning.

3.2. Communications Network Capital

The AMI communications network hardware and installation phase involves the physical roll-out of the communications infrastructure (collection points and wide area network (WAN) hardware) in the field. First, the communications network is installed in each operating center area to provide immediate visibility to the meters that will be installed. Network communication implementation includes field survey, installation of communication equipment and testing of communication equipment. It is estimated that there will be approximately 20,000 network devices (routers and collectors) across the Ameren Illinois' service territory.

Table 5: Communication Network Costs (in $ millions, over 20 years)

Communication Network Cost Drivers	Capital
AMI Communications Equipment	$17
AMI Communications Equipment Installation	$4
Make Ready Distribution Work	$8
TOTAL	**$29**

3.3. Information Technology (Applications and Operations) Capital

This cost category includes the capital implementation costs associated with the IT systems and integration hardware, software, development, security and IT project management.

Key components of AMI-related IT systems:

- AMI IT systems include head-end systems to communicate with the AMI network, capture meter data and send control commands to the meter.
- Head-end systems transfer data to a Meter Data Management System (MDMS) where meter data is validated against acceptance rules to ensure data quality. Estimations are done for missing data and edits are made to some data elements.
- Storage systems are needed, as meter data increases exponentially over current needs, increasing the importance of systematic data management.

- Data will need to be shared by several systems, and it requires an integration platform to allow sharing of the information between various enterprise systems (e.g. providing data for various applications such as billing, customer service and customer analytics).
- Security of the AMI network, including planning and implementation of security architecture to protect customer and operational data, is required.

Table 6: Information Technology (Applications and Operations) Costs (in $ millions, over 20 years)

Information Technology (Applications and Operations) Cost Drivers	Capital
Hardware	$12
Software	$5
Labor	$35
Integrated Operations Center	$3
TOTAL	**$55**

Outlined below are further details on the key elements of Ameren Illinois' anticipated AMI IT infrastructure:

- Hardware
  - Servers for Enterprise Service Bus (ESB), the middleware applications that moves data between applications
  - Network Operations Hardware
  - Servers for AMI Applications
  - Servers for Database Applications
  - Data Storage

- Software
  - AMI Head End
  - Application Software for Data Transmission
  - Meter Data Management System
  - Data Analytics Software
  - ESB Tools
  - Integrated Operations Center AMI Network Monitoring and Work Management tools

- Labor
  - Business Process Review and Design
  - Requirements Definition
  - AMI Head End & MDMS Design and Integration
  - ESB Implementation
  - IT Environment Set Up, Installs, etc.
  - Development and Integration
  - Testing and Test Support
  - Data Analytics Support
  - Security and Event Planning

- Integrated Operations Center (IOC)
  - Design and construction of the Integrated Operations Center facility in Decatur, IL
  - Business process design and implementation for the IOC

Both Ameren Illinois resources and contractor resources will be employed for the integration and development of IT systems. Furthermore, fees will need to be paid to vendors for product support and servicing.

3.4. Program Management Capital

A long-term strategic initiative such as AMI deployment requires a substantial amount of resources for program delivery activities. Ameren Illinois estimates that $10 million will be needed to fund program management activities for the 100% deployment of AMI

Table 7: Program Management Costs (in $ millions, over 20 years)

Program Cost Drivers	Capital
Program Management	$10

Program Management activities include

- **Governance:** Oversight, program prioritization and approval, establishing program sponsorship and accountability,
- **Quality Management:** The development and management of standard processes and practices to manage quality across the program
- **Program Scheduling and Staffing**: The management of integrated timelines and dependencies; securing and allocating resources to satisfy demand in a timely manner
- **Issue and Risk Management:** A standard methodology and tool for reporting, prioritizing, and escalating issues to ensure timely resolution; the development and management of standard risk identification and response capabilities to manage risk across the program
- **Project Communications and Reporting**
- **Financial/Benefits Realization and Regulatory Management:** The management and production of financial planning and reporting; management of benefits realization and business cases to ensure business benefits are measured and achieved; single point of contact to manage compliance with requirements of Commission
- **Change Control Process:** The management and prioritization of new projects or new requirements, including change orders
- **Release Management:** The management of an integrated release strategy to support organization-wide prioritization, dependencies and risk
- **Sourcing Strategy and Management:** Single point of contact to manage compliance with requirements of legal department
- **Vendor/Contract Management:** Integrated management of key vendors, including contractual, administrative and communication functions

The program management work will be performed by a combination of internal and external resources.

3.5. AMI Operations Support of Deployment Capital

This category of costs represents the costs of start-up and on-going operations for supporting AMI operational activities throughout the business case evaluation period of 20 years. As outlined in the following table, AMI operational costs include costs for metering operations, communications operations and consumer education. The 20-year total cost in this area is $23 million in capital.

Table 8: AMI Operations Costs (in $ millions, over 20 years)

AMI Operations Cost Drivers	Capital
Metering	$5
Communications	$2
Miscellaneous (Contingency)	$16
TOTAL	**$23**

3.5.1. Metering Operations

Metering operations includes all costs related to managing Ameren Illinois' AMI metering operations during implementation. Included in this are the following areas:

- **Meter Inventory Management:** Managing the inventory for 100% deployment of meters over the 8-year rollout
- **Meter Warehousing:** Facility costs for housing the meter inventory, especially during the initial rollout
- **Meter Testing and Make-ready:** Initial testing of meters before installation to ensure the meters are fully functional

3.5.2. Communications Operations

Communications operations include all aspects supporting the deployment of the AMI communications network. Personnel includes network operations engineers, field / telecom operations technicians and supervisors, as well as Network Operations Center infrastructure specialists.

3.5.3. Miscellaneous (Contingency)

Ameren Illinois' project management best practices require a risk based contingency to be included as part of authorized project costs. Ameren Illinois' AMI project team has done an analysis on the remaining risk items for the expansion of AMI to 100% of its customers to develop the contingency amount carried in the business case.

3.6. Meter Reading Operations and Maintenance Costs

Meter Reading Costs are the manual methods required to supplement the AMI delivered benefits in order to meet Ameren Illinois' AMI-related performance metrics as established in Illinois Public Acts 97-616 and 97-646.

Table 9: Meter Reading Costs (in $ millions, over 20 years)

Meter Reading Cost Drivers	O&M
Manual Disconnect & Read to Meet Metrics	$1
AMI Communications Network	$12
Accelerated Depreciation for Existing Meters	$1
Electric Meter Failures	$2
TOTAL	**$16**

3.6.1. Manual Disconnect & Read to Meet Metrics

Ameren Illinois estimates that, since the deployment of AMI meters didn't begin until 2014 and will end in 2019, the AMI system won't be fully operational and deployed in time to meet the performance metrics, specifically in the areas of disconnects to reduce Consumption on Inactive Meters (CIM) and estimated bills. In order to reduce consumption on inactive meters, Ameren Illinois estimates that additional physical disconnects will need to occur to prevent usage on accounts that have had their service stopped. The AMI system will ultimately provide the capability to remotely physically disconnect electrical service to customers that have stopped service on their account. Until the AMI system is fully deployed and operational, additional manual disconnects will need to occur to meet the performance targets.

In order to reduce the amount of uncollectible revenue that is written off each year, Ameren Illinois estimates that additional physical disconnects will need to occur to prevent additional usage on accounts that are overdue. The AMI system will provide a remote disconnect capability that will address this need once the AMI system is fully implemented.

To date, Ameren Illinois has not spent any addition O&M to do additional manual reads to meet the estimated reads metric.

3.6.2. AMI Communications Network

Ameren Illinois has included O&M costs over the life of the project for make ready of the poles to receive the network equipment. Typically, this work is considered capital, except in situations where Ameren Illinois needs to add a new pole but keep the same conductors. Ameren Illinois' Plant Accounting has determined the labor to temporarily suspend the conductors and then rehang them on the new pole is considered O&M. Additionally, the ongoing cellular modem licenses for the AMI network's backhaul communication channel from the Wide Area Network (WAN) to Ameren Illinois' data center is considered O&M.

3.6.3. Accelerated Depreciation for Existing Meters

The final cost driver related to the AMI Metering Equipment implementation is the accelerated depreciation for the existing non-AMR meters and applicable AMR meters & infrastructure. Since the AMI meters will be rolled out to 100% of customers over the 8 year deployment period, all existing non-AMR meters and AMR meters will be replaced during that timeframe. Many of these meters will still have a depreciable life remaining at the point they are replaced. Therefore, the costs for accelerating the remaining depreciation for these meters are included in this analysis, which is consistent with the guidelines recommended by the Illinois Statewide Smart Grid Collaborative.

The existing depreciation schedule calls for depreciation on existing meters (both AMR and non-AMR) to total $85 million in 2012-2031 and $3 million in 2032 and beyond. The accelerated depreciation schedule for the existing meters based on AMI implementation totals $88 million in 2012-2031. While the total depreciated is the same for the existing & accelerated schedules (including years after 2031), the difference between the existing and accelerated depreciation for each year is included in the cost estimates.

3.6.4. Electric Meter Failures

Ameren Illinois has included the labor cost to remove and replace electric meters that fail after installation during the five year warranty period. If the meter fails after the five year warranty period, Ameren Illinois replaces the meter as a capital expenditure, which is included in our AMI Meters Capital cost item. Ameren Illinois has assumed a 0.5% failure rate of AMI meters during the warranty period.

3.7. Information Technology (Applications and Operations) Operations and Maintenance Costs

Table 10: Information Technology Costs (in $ millions, over 20 years)

Information Technology (Applications and Operations) Cost Drivers	O&M
Hardware	$4
Software	$28
Labor	$59
Integrated Operations Center	$22
Asset Management	$2
TOTAL	**$115**

3.7.1. Hardware

The hardware O&M consists of annual license fees for the various equipment used by the AMI solution to move data from the Wide Area Network through the various applications that use AMI data in Ameren Illinois' data center.

3.7.2. Software

The software O&M are the annual software maintenance fees for each application that Ameren Illinois uses to support the AMI solution. Examples of applications used on the AMI program that require annual software maintenance fees include:

- AMI Head End (manages the AMI Field Area Network)
- Meter Data Management System
- Enterprise Service Bus
- Meter Asset Management System
- Data Warehouse
- File Transfer Applications
- Residential Customer Web Portal
- Cloud Based Meter Data Analytics
- Integrated Operations Center Work Management System

3.7.3. Labor

Information Technology O&M labor includes application development specialists, infrastructure specialists, network communication technicians, RF engineers, business analysts, and application testers who are responsible for ensuring the AMI solution has high availability and is routinely upgraded as new functionality requests are received from Ameren Illinois Customer Service and Division Operations. Also included is each AMI IT organization's supervision.

3.7.4. Integrated Operations Center

Ameren Illinois' Integrated Operations Center (IOC) monitors the AMI network to ensure the smooth flow of AMI data from the endpoint through the field area network into the data center to the appropriate application that uses the AMI data for daily utility operations. The IOC is co-located with Ameren Illinois' dispatch center for synergies in identifying and remotely troubleshooting communication and electric network issues. After the project team disbands, the IOC will serve as the center of Ameren Illinois' expertise on AMI operations.

3.7.5. Asset Management

Asset Management Planning Support costs include the development of enhanced asset planning analysis tools and software to enable better forecasting and planning. Additionally, there is an on-going maintenance cost for the tools and software that will be developed.

3.8. Management and Other Costs (Operations and Maintenance)

Table 11: Management and Other Costs (in $ millions, over 20 years)

Management and Other Cost Drivers	O&M
Program Management	$1
Metering Operations	$0
Change Management	$2
AMR Termination Fee	$7
Miscellaneous	$0
Customer Education – Deployment & Initial Functionality	$8
Demand Response	$5
Energy Efficiency	$5
Electric Vehicle Enhancement	$25
Customer Technology Interface & Support	$23
TOTAL	**$76**

3.8.1. Program Management

Subsequent to the full functionality integration of the AMI solution into Ameren Illinois' Energy Delivery Business Suite of Applications, the AMI project team will continue to oversee not only the capital investment required for the additional deployment of meters, modules, and network, but will also retain accountability for the ongoing operations and maintenance of the AMI solution. Thus, a portion of the AMI project team's program management staff will be apportioned to O&M as the AMI project team fixes new defects, performs upgrades, and maintains the AMI solution infrastructure.

3.8.2. Metering Operations

The Metering Operations O&M is for the ongoing software licenses for the AMI endpoint deployment software known as ProField. ProField is the work management application used by the deployment subcontractor to handle all aspects of the electric meter installation. ProField allows an installer to capture meter data at the install, take pictures of the installation, perform pre-job safety checks, and capture GPS coordinates.

3.8.3. **Change Management**

Ameren Illinois determined at the outset of the program to implement a robust internal change management program due to the large amount of people, process, and technology changes an AMI solution drives in an organization. The tasks performed by the change management team include:

- Creating a Change Management Strategy to identify an overarching plan to ensure the organization fully adopts the changes brought about by AMI
- Organizational Impact Analysis to determine the amount of change and the criticality of the change due to AMI on specific organizational positions
- Development of training materials, instructor led training, and computer based training for new AMI functionality
- Establishment of multiple internal communications channels (meetings, websites, change champions, etc) to allow co-workers to receive change information at the right time in their preferred method of learning
- Organizational surveys to determine the effectiveness of the change management tactics.

3.8.4. **AMR Termination Fee**

Expansion of the AMI deployment to 100% will result in a termination fee associated with the existing AMR contract.

3.8.5. **Miscellaneous**

The O&M costs in this category are for AMI Project Team office supplies, ongoing maintenance of the AMI Test Lab in Collinsville, and Mobile Data Terminals for Meter Specialists.

3.8.6. **Customer Education – Deployment and Initial Functionality**

The success of AMI program is contingent on the ability of Ameren Illinois to communicate with customers, with a specific focus on educating them on the safety and capabilities of the AMI system. The focus is to enable the customer so that customer direct benefits are maximized. This also includes both broad public education and specific customer education on the positive impacts of AMI technology, implementation success stories, how AMI creates value in energy conservation, and/or specific details on participation in Demand Response/Energy Efficiency programs. In addition, customer education efforts will include instruction on how to use customer self-service and web portal tools. Ameren Illinois has begun and will continue to execute its customer education plan outlined in its approved AMI Plan. The goals of the plan are to help our customers and stakeholders:

- Understand AMI to be an integral component of the Modernization Action Plan (MAP).
- Understand and be able to communicate the benefits of AMI to their families, friends, neighbors, constituents and others.
- Understand the benefits of advanced meters and pricing programs (such as Peak Time Rewards).
- Understand AMI is a "normal" course of doing business with Ameren Illinois.
- Use an effective "two-way" communication channel to provide feedback, ask questions and gather information.

As part of the communication to customers, Ameren Illinois has performed a customer segmentation study to determine what messaging themes resonates with the different customer segments. Ameren Illinois has used these customer segments in developing its communication collateral along its different communication channels and self-service options.

3.8.7. **Demand Response**

Customers, in the future, will have the choice to opt-in to a variety of pricing programs such as Peak Time Rewards (PTR), Critical Peak pricing rate, Direct Load Control program, or Time of Use program enabled by the

AMI solution. Costs associated with this program include technology such as in-home displays, programmable control thermostats, and home energy management systems. The AMI solution currently enables the use of in-home devices using the Home Area Network Zigbee Protocol standard. Ameren Illinois believes these programs will be provided through regulatory driven initiatives provided by the utility, such as Peak Time Rewards, and through Retail Electric Suppliers as they develop programs to differentiate themselves in the energy supply market.

3.8.8. Energy Efficiency

As customers are more aware of their energy use, there is a natural learning that takes place and results in overall usage reduction. The costs associated with the Energy Efficiency program include the home energy devices such as in-home displays or home energy monitors or messages customized to one's personal mobile devices. As stated previously, Ameren Illinois believes it will be the Retail Electric Suppliers who develop these types of programs.

3.8.9. Electric Vehicle (EV) Enhancement

AMI combined with smart charging technologies will allow EV owners to charge their vehicles at non-peak times when electricity rates are cheapest. The costs associated in this model are driven by the incremental cost of electric vehicles relative to conventional vehicles. It is assumed that the PEV premium is $9,500 in 2012 and declining at a rate of 16% in the first ten years of the forecast and 8% in the last ten years.

3.8.10. Customer Technology Interface & Support

AMI when used in conjunction with Demand Response technology is an enabler to provide new options for customers who choose to opt-in to Demand Response and Energy Efficiency programs. The IT costs associated with integrating to these new systems is estimated in these costs. The integration interfaces would leverage industry standard interfaces where applicable such as NIST standards for integrating to new head-end Demand Response system (DRMS), Green Button interfaces for customer web portals, and interfaces to third-party vendors providing additional enabling technologies that may be leveraged by Ameren Illinois customers in the future.

4. Ameren Illinois AMI Program Operational Benefits

Ameren Illinois has conducted a thorough assessment of all the operational benefits that it expects to accrue through the 100% AMI implementation within 8 years. Included in this analysis are direct operational benefits realized by Ameren Illinois and passed along to customer rates. These benefits are evaluated over a 20 year period and are expressed in incremental terms over the "business as usual" case.

The following methodology was utilized to calculate steady-state benefits associated with the AMI implementation:
(1) Define the value drivers of the AMI solution components
(2) Identify and isolate the affected baseline costs and revenues that will be impacted
(3) Research and identify relevant cost savings and/or loss prevention percentages to be applied to the affected baseline

Over 20 years, Ameren Illinois expects financial benefits of approximately $1.6 billion. The following table outlines a summary of the major quantifiable benefits expected out of the AMI implementation.

Table 12: Key Benefit Drivers (in $ millions, over 20 years)

Key Benefit Components	Total
O&M	
Meter Reading	$263
Field & Meter Services	$242
Unaccounted for Energy	$35
Customer Care Improvements	$13
Information Technology (Applications and Operations)	$3
Distribution System Management	$14
Subtotal of O&M Benefits	**$570**
Capital	
Distribution System Management	$13
Outage Management	$12
Asset Management Planning	$9
Avoided Meter Purchases	$26
Subtotal of Capital Benefits	**$60**
Customer	
Consumption on Inactive Meters	$22
Uncollectible Expense	$67
Demand Response	$590
Energy Efficiency	$35
Electric Vehicle Enhancement	$221
Carbon Reduction	$16
Value of Reduced Outage Duration	$35
Subtotal of Customer Benefits	**$986**

TOTAL OF O&M, Capital, and Customer Benefits	**$1,616**

4.1. Meter Reading Benefits

Ameren Illinois has been an early adopter of automated meter reading (AMR). Approximately 680,000 electric meters were converted to AMR – representing more than half of Ameren Illinois' electric customers. As a result of this automated meter reading, many of the meter reading labor benefits have been previously realized. Reduction in meter reading costs from the remaining 574,000 manual electric meters represents the largest area of benefits expected from Ameren Illinois' AMI implementation plan. Meter reads that are traditionally conducted through physical site visits to the customer premise can instead be done remotely through the AMI system. Benefits associated with reduction in meter reads represent the reduction in manual meter reading labor costs, associated IT costs, as well as vehicle / transportation costs.

Ameren Illinois estimates that 100% deployment of AMI over 8 years will result in meter reading cost savings of $263 million over a 20 year period.

Table 13: Meter Reading Cost Savings Breakdown (in $ millions, over 20 years)

Reduction in Meter Reading Costs	Cumulative Benefits
Reduction in Manual Meter Reading Expenses	$120
Reduction in AMR Meter Reading Expenses	$140
Reduction in Manual and AMR Meter IT Costs	$2
Reduction in On-Cycle Meter Reading Vehicle Expense	$1
TOTAL	**$263**

4.1.1. **Reduction in Manual Meter Reading Expenses**

Of the 574,000 electric meters that are manually read, 20% of on-cycle reads are performed utilizing internal Ameren Illinois labor while the remaining reads are performed by contractors. Cost savings through the reduction in manual meter reads will be realized through a reduction in both in-house and contractor labor costs.

Meter reader workforce reductions are planned over the course of the 8-year AMI implementation, and Ameren Illinois is planning to realize these workforce reductions through natural attrition and work re-assignment over time.

Quantifiable benefits related to manual meter reading savings are expected to be $120 million over a 20 year business case time horizon. These cost savings take into account meter reads conducted by both internal meter readers as well as external contractors.

4.1.2. **Reduction in AMR Meter Reading Expenses**

Ameren Illinois will replace all of its AMR meters with AMI meters starting in 2017. All costs associated with AMR meter reading in the form of fees paid to external vendors will be eliminated as AMI meters replace existing AMR meters.

By eliminating these AMR costs over the AMI implementation time frame, Ameren Illinois expects to realize cost savings related to AMR meter reading of approximately $140 million over a 20 year business case time horizon.

4.1.3. Reduction in Manual Meter IT Costs

O&M costs associated with the IT systems that support existing manual meter reads will be eliminated with the deployment of AMI meters. Benefits include cost savings associated with the support and upgrade of meter reading devices as well as software licensing and maintenance.

The current cost to support the existing MVRS hardware and software is roughly $175,000 per year. Ameren Illinois expects to be able to save 60% of these costs after deployment.

Ameren Illinois estimates reduction in manual meter IT costs to be approximately $2 million over the 20 year business case time horizon.

4.1.4. Reduction in On-Cycle Meter Reading Vehicle Expense

As non-AMR meters get replaced by AMI smart meters, the reduction in the need for manual meter reads will result in a reduction in associated vehicle costs for Ameren Illinois. Vehicle-related benefits include cost savings from fewer vehicles, fuel costs, vehicle insurance, and vehicle maintenance.

The current annual cost to operate and maintain vehicles for meter reading purposes is approximately $500,000. With AMI, Ameren Illinois expects reduction in manual and special meter reads to reduce vehicle costs by approximately $1 million over the 20-year business case time horizon.

4.2. Field and Meter Services Benefits

AMI's smart metering and communication infrastructure enables utilities to perform several functions remotely that would otherwise require a field visit to the customer premise. As a result, significant cost savings through the reduction in the number of personnel and vehicles for field and meter services can be achieved. Benefits in this area can be seen in the reduction in manual disconnect / reconnect of meters, single light outages, need for manual re-reads, as well as customer equipment problem outages.

Ameren Illinois estimates that 100% deployment of AMI over 8 years will result in field and meter services cost savings of $242 million over the 20 year business case time horizon.

Table 14: Field and Meter Savings Breakdown (in $ millions, over 20 years)

Field & Meter Services	O&M Benefits
Reduction in Manual Disconnect / Reconnect of Meters	$147
Reduction in Manual Off-Cycle / Special Meter Reads	$40
Reduction in Nuisance Stopped Meter Orders	$3
Reduction in Field Services Vehicle Expense	$30
Reduction in Customer Equipment Problem Outages	$3
Reduction in "OK on Arrival" Outage Field Trips	$18
Salvage Value of Replaced Meters	$1
TOTAL	**$242**

4.2.1. Reduction in Manual Disconnect / Reconnect of Meters

The remote connect / disconnect feature of AMI smart meters enables utilities to turn on and off services for new and cancelled accounts remotely without a field trip. This benefit not only applies to the ability to turn on and off services for regular move-in / move-out of customers, but also provides the ability to cancel service for non-paying customers. As a result, significant cost savings can be realized through the reduction in need for personnel and transportation costs to turn on / off services. Cost savings will also be seen through the time saved due to reduction in meter access challenges as a result of AMI.

From 2010 to 2014, Ameren Illinois annually received about 245,000 orders for electric disconnect / re-connect per year, of which about 84,000 per year were disconnects for non-pay. Ameren Illinois expects cost savings of approximately $147 million from reduced labor associated with the ability to remotely turn on/off energy service over 20 years.

4.2.2. Reduction in Manual Off-Cycle / Special Meter Reads

Ameren Illinois currently incurs significant costs to conduct manual off-cycle special meter reads. These reads are conducted for tenant changes, re-reads, high bill inquiries, and other instances when a reading is needed off the normal read cycle reads etc. Labor cost savings will be realized through reduction in off-cycle / special meter reads as a result of AMI.

Ameren Illinois annually conducts approximately 121,000 off-cycle reads. Quantifiable benefits related to off-cycle meter reading savings are expected to be approximately $40 million over a 20 year business case time horizon.

4.2.3. Reduction in Nuisance Stopped Meter Orders

Currently, Ameren Illinois receives approximately 22,200 orders for stuck / stopped electric meters annually. Of these, approximately 30% of the orders are found to be invalid / nuisance by the field & meter services personnel. With AMI, Ameren Illinois will be able to remotely detect whether the meter is stopped or malfunctioning, thereby eliminating the need for a premise visit to address an invalid stopped meter order.

Over the 20-year business case time horizon, Ameren Illinois expects benefits of approximately $3 million related to reduction in nuisance stopped meter orders.

4.2.4. Reduction in Field Services Vehicle Expense

With the reduction in field service visits to customer premises due to the above factors, there will also be a reduction in associated vehicle costs for Ameren Illinois. Vehicle-related benefits include cost savings from fewer vehicles, fuel costs, vehicle insurance, and vehicle maintenance.

The total benefit Ameren Illinois expects to realize through reduction in off cycle field services vehicle expense will be approximately $30 million over the 20-year business case time horizon.

4.2.5. Reduction in "Customer Equipment Problem" Outage Field Trips

With AMI, Ameren Illinois will be able to determine whether the cause of an outage is the result of an electrical problem with the customer's equipment. This automated determination will help save dispatch labor and transportation costs for customer incidents that involve equipment failure.

Ameren Illinois estimates that while approximately 90% of "Customer Equipment Problem" related field trips can be eliminated as a result of AMI, 10% of orders will still require a field trip due to problems inside the meter base. Cost savings of approximately $3 million are expected over a period of 20 years.

4.2.6. Reduction in "OK on Arrival" Outage Field Trips

AMI implementation is expected to result in cost savings associated with reduced outage "OK on Arrival" field trips to customer premises. With the ability to provide near real-time power and outage status information, AMI systems are able to test for loss of voltage at the service point and both detect outage conditions as well as obtain restoration status indication. As a result, "OK on Arrival" field trips will be virtually eliminated, in AMI areas, thereby leading to cost savings.

Ameren Illinois currently works about 8,200 orders for outages (both storm and non-storm related) that upon investigation are found to be "OK on Arrival". Ameren Illinois estimates that it will realize financial benefits related to reduction in "OK on Arrival" field trips of approximately $18 million over the 20-year business case time horizon.

4.2.7. Salvage Value of Replaced Meters

A small financial benefit of replacing electro-mechanical and AMR meters as part of Ameren Illinois' AMI deployment plan is the salvage value of meters that have remaining useful life.

Ameren Illinois has estimated a conservative salvage value of $0.65 per meter, thereby leading to benefits of approximately $1 million for the utility over the 20-year business case time horizon.

4.3. Unaccounted for Energy Benefits

Unaccounted for Energy (UFE) in the areas of meter tampering, energy theft, meter inaccuracy, and dead / stopped meters results in significant revenue loss for utilities. Through the use of smart meters and sophisticated data analytics algorithms, UFE can be detected early and revenue losses related to unmetered energy can be reduced.

Ameren Illinois estimates that 100% AMI implementation in 8 years will help increase revenue from reduction in UFE by $35 million over a 20 year period.

Table 15: Field and Meter Savings Breakdown (in $ millions, over 20 years)

Reduction in Unaccounted for Energy	Cumulative Benefits
Theft / Tamper Detection & Reduction	$32
Faster Identification of Dead Meters	$3
TOTAL	**$35**

4.3.1. **Theft / Tamper Detection & Reduction**

AMI systems significantly aid in the early detection of meter tampering and energy theft. Through the use of analytics software and AMI functionality that enables frequent recording of smart meter energy consumption, the detection of anomalous patterns of energy resulting from theft and tampering can be discovered. According to Chartwell, a market research company for utility customer care, marketing and smart grid, theft is estimated at 1% of a utilities' revenue.[2] Thus, the use of AMI can significantly reduce energy and revenue losses associated with energy theft.

In reviewing various public utility AMI filings, Ameren Illinois observed that other utilities estimated savings in the range of 0.5% - 1% of revenue associated with each AMI meter. Ameren Illinois conservatively estimates that AMI will help the utility save 0.25% of theft / tamper-associated revenue. This will result in cutting existing residential line losses by about 2.9%. Over a 20 year period, Ameren Illinois expects financial benefits from reduction in energy theft for residential customers to be approximately $32 million.

4.3.2. **Faster Identification of Dead Meters**

The implementation of AMI systems helps utilities more quickly identify dead and/or stopped meters that can no longer measure electricity due to meter failure. This early identification helps utilities quickly take steps towards repairing or replacing the dead meter, thereby reducing potential revenue losses.

Ameren Illinois currently receives approximately 2,200 valid orders annually for dead residential meters with average residential consumption of about 1,000 kWh per month. With the use of AMI and a charge back period of 60 days, Ameren Illinois expects to realize financial benefits associated with the early identification of dead meters of approximately $3 million over a 20 year time period.

4.4. Customer Care Improvement Benefits

An important benefit of AMI is the cost savings realized through efficiency improvements in customer call volume and management. Meter reading errors are expected to be virtually eliminated and the need for calculation of estimated bills due to access issues will be significantly reduced. Efforts to raise awareness regarding AMI through marketing campaigns and customer education will increase customer adoption of self-service leading to an overall reduction in call volume. However, more complicated billing problems may increase due to expanded dynamic pricing. The potential to reduce float between meter read and customer billing will also drive greater benefits for Ameren Illinois.

Over a 20 year period, Ameren Illinois estimates $13 million in cost savings through efficiency improvements in customer call volume and management as a result of AMI.

[2] Chartwell Report, 11th Edition on AMI/AMR

Table 16: Efficiency in Billing Breakout (in $ millions, over 20 years)

Customer Care Improvements	O&M Benefits
Customer Service Support of AMI Implementation	$1
Reduction in Estimated Bills	$0
Reduction in Call Volume	$10
Reduction in Float between Meter Read and Customer Billing	$1
Reduction in Customer Accounts Management	$1
TOTAL	**$13**

4.4.1. Customer Service Service Support of AMI Implementation

Ameren Illinois' actual benefits realized to date include customer service personnel assigned as capital resources to the AMI program for business process design and testing of AMI functionality. These resources are included in the AMI program's capital costs.

4.4.2. Reduction in Estimated Bills

The ability to remotely read meters on a frequent basis greatly reduces estimated bills that often result from meter access issues that currently prevent meter readers from obtaining reads in hard to access areas at the customer premise. Fewer customer service resources are thus expected to review exception reports, resolve billing errors and process adjustments.

Ameren Illinois has already received these benefits in its existing AMR areas. While it is believed that a reduction in estimated bills from its non-AMR areas will result in reduced workload for Ameren Illinois' Customer Accounting Department, there is likely to be an increase in more complicated billing problems due to expanded dynamic pricing. At this point, Ameren Illinois is taking a conservative approach and assuming that AMI will have a neutral effect on its Customer Accounts Department due to estimated bill issues.

4.4.3. Reduction in Customer Call Volume

Comprehensive marketing campaigns and customer awareness programs will educate customers about the self-service options available to them from Ameren Illinois throughout the AMI roll-out.

Ameren Illinois receives approximately 5 million calls annually related to customer inquiries. Ameren Illinois is currently planning on further developing its customer self-service capabilities, including web and IVR enhancements channels. Ameren Illinois plan to increase the self-service marketing efforts during the AMI roll-out, encouraging portal use and promoting self-service within AMI communications. Ameren Illinois estimates it will see approximately a 5% reduction in call volume as a result of greater self-service adoption. This will also be driven by lower bill inquiry call volume due to reductions in estimated bills. The reduction in call volume over the 20 year business case time horizon will produce $10 million in cost savings.

4.4.4. Reduction in Float between Meter Read and Customer Billing

Ameren Illinois expects AMI to enable all accounts within AMI territories to be billed on the second day of the billing window. As a result of AMR implementation, Ameren Illinois is already able to receive a majority of its meter readings on the second day within the window. However, the remaining bills (about 20%) that are currently produced during the third and fourth days will now be generated during the second day as a result of AMI. This will accelerate Ameren Illinois' revenue stream and improve its cash flow.

Over the 20 year business case time horizon, Ameren Illinois expects benefits related to reduction in float between meter read and customer billing of approximately $1 million dollars.

4.4.5. **Reduction in Customer Accounts Management Costs**

Detailed information regarding the status of each AMI meter will allow Ameren Illinois to detect stopped or faulty meters on a real-time basis. Currently, meters that have stopped or are not registering an accurate reading as a result of device failure require a manual intervention to investigate the issue. Also, AMI will provide data to resolve billing exceptions faster, either through automation of the exception management process or through quicker access to data in the customer's meter. Through the implementation of AMI, Ameren Illinois expects to be able to reduce the customer accounts effort required to intervene on a stopped meter incident.

Over the 20 year period, the reduction in customer accounts back-office costs is estimated at $1 million dollars through a reduction in effort required to address stopped meters.

4.5. Information Technology (Applications and Operations) Benefits

Ameren Illinois currently uses 1.5 FTEs to support its existing Meter Data Management (MDM) for Power Smart Pricing / Real Time Pricing programs. Furthermore, in addition to the $36,000 it pays in annual software maintenance fees, it has also budgeted associated hardware purchase and upgrade costs. The new Meter Data Management System implemented with AMI will handle the data processing for these accounts. Thus, these costs will not be incurred after the implementation of the AMI project, resulting in a benefit of $3 million over the 20 year evaluation period

4.6. Distribution Network Efficiency Benefits

Ameren Illinois expects AMI to enable improvements in operating and maintaining the electrical distribution grid.

Over a 20 year period, Ameren Illinois estimates $14 million in cost savings through distribution network efficiency benefits as a result of AMI.

Table 17: Distribution Network Efficiency (in $ millions, over 20 years)

Distribution Network Efficiency	O&M Benefits
Distribution System Management	$1
Outage Management	$8
Asset Management Planning	$5
TOTAL	**$14**

4.6.1. **Distribution System Management**

Interval consumption data can be aggregated at the transformer level to help identify under-used and over-loaded transformers, as well as to properly size replacement transformers.

From 2010 through 2014, the average O&M expense for the maintenance of overhead lines, underground lines, and line transformers was $84 million per year.

At 100% AMI deployment, Ameren Illinois expects 0.1% reduction in O&M expenses related to low voltage distributed system management. Over the 20-year business case time horizon, this results $1 million in O&M avoided cost.

4.6.2. **Outage Management**

AMI will enable Ameren Illinois to obtain automated outage notification from the smart meters, receive specific location information as well as verify when power has been restored. These features will allow crews to be deployed more efficiently to outage areas further improving crew management efficiency. Additional truck rolls will also be eliminated by verifying, remotely, that all customers in an area have been restored before dispatching the crew to the next location.

With the implementation of AMI, outage restoration spend will improve by 10% of cost savings, $8 million in O&M.

4.6.3. **Asset Management Planning**

Information received through AMI will provide more granular level system health and performance details. Using more detailed information from AMI enables Ameren Illinois to more accurately forecast load growth and evaluate system investments resulting in improved asset planning and strategies.

Over the 20 year business case time horizon improved asset planning and strategies will enable resource leveling and result in a total benefit of $5 million in O&M.

4.7. Capital Benefits

Ameren Illinois also expects AMI to enable improvements in the distribution system planning efforts. AMI will provide detailed information across the distribution network that can be used to optimize investments in infrastructure improvements. Examples of data available by AMI that can be used in asset management are:

- Interval (time-based) consumption data at the customer level (and ability to aggregate up to transformer and circuit levels)
- Voltage information collected at each premise
- Momentary outage information

The total benefit from Improved Capital Spend Efficiency over the 20-year business case timeframe is $60 million.

Table 18: Capital Benefits Breakout (in $ millions, over 20 years)

Capital Expenditures	Capital Benefits
Distribution System Management	$13
Outage Management	$12
Asset Management Planning	$9
Avoided Meter Purchases	$26
TOTAL	**$60**

4.7.1. Distribution System Management

Interval consumption data can be aggregated at the transformer level to help identify under-used and over-loaded transformers, as well as to properly size replacement transformers.

From 2010through 2014, the average capital investment by Ameren Illinois in the low voltage distribution system was approximately $72 million per year.

At 100% AMI deployment, Ameren Illinois expects 1% capital savings related to low voltage distributed system management. Over the 20-year business case time horizon, this results in capital benefits of approximately $13 million.

4.7.2. Outage Management

AMI will enable Ameren Illinois to obtain automated outage notification from the smart meters, receive specific location information as well as verify when power has been restored. These features will allow crews to be deployed more efficiently to outage areas further improving crew management efficiency. Additional truck rolls will also be eliminated by verifying, remotely, that all customers in an area have been restored before dispatching the crew to the next location.

With the implementation of AMI, outage restoration spend will improve by 10% resulting in $12 million in Capital savings.

4.7.3. Asset Management Planning

Information received through AMI will provide more granular level system health and performance details. Using more detailed information from AMI enables Ameren Illinois to more accurately forecast load growth and evaluate system investments resulting in improved asset planning and strategies.

Over the 20 year business case time horizon improved asset planning and strategies will enable resource leveling and result in a total benefit of $9 million in Capital.

4.7.4. Avoided Meter Purchases

This benefit category represents the cost savings realized by not having to replace existing non-AMR and AMR meters on an annual basis without AMI implementation. These include cost savings from reduced additions (meter costs), reduced replacements (meter costs), as well as reduced meter testing and installation costs (labor and material). The benefit from avoided meter purchases, however, is partially offset by the cost of on-going replacement of AMI meters due to normal failure rates.

With an expected meter replacement rate of 3% annually, Ameren Illinois estimates cost savings from avoided meter replacements at approximately $26 million over 20 years.

4.8. Ameren Illinois AMI Customer/Societal Benefits

While the above benefits are largely operational in nature and will flow to customers through Ameren Illinois and its operations and rates, other benefits from AMI will be flow directly to Ameren Illinois customers. These will be captured by customers in the form of reduced energy usage and the potential for special rate plans in which Ameren Illinois' customers can engage.

Quantified Customer/Societal Benefits are benefits that impact Ameren Illinois customers and are realized by those customers or by society as a whole, not by Ameren Illinois.

Table 19: Quantified Customer Benefit Breakout (in $ millions, over 20 years)

Quantified Customer Benefits	Cumulative Benefits
Reduced Consumption on Inactive Meters	$22
Reduced Uncollectible / Bad Debt Expense	$67
Customer Engagement Benefits	
Demand Response	$590
Energy Efficiency	$35
Electric Vehicle Enhancement	$221
Carbon Reduction	$16
Customer Outage Reduction Benefit	$35
TOTAL	**$986**

4.8.1. Reduced Consumption on Inactive Meters

Ameren Illinois assigns electric meters to customer accounts and bills for usage on those meters to the assigned customer accounts. When a customer disconnects electric service at a premise (most often when they are vacating the premise), the customer account is disassociated with that electric meter. In the vast majority of cases, there is a corresponding connect request of electric service to the same premise (most often when a new occupant takes possession of a premise) on a date very close to the disconnect date.

Ameren Illinois does not physically disconnect electric service on the premise when a disconnect occurs in its existing AMR areas, and in some instances in its existing non-AMR areas. Rather, a "soft disconnect" usually occurs whereby a customer account is not associated with an electric meter during the gap between disconnect and connect. During the same gap, electric usage may still occur in some cases. Since there is not a customer account associated with the electric meter, no customer is billed for this usage.

A key feature of the AMI meters and infrastructure is the provision of a remote disconnect feature that will physically disconnect power to a premise when a disconnect request occurs. This will provide a significant decrease in unaccounted for consumption when meters are inactive.

Ameren Illinois estimates that approximately 12.1 GWh of electric energy is consumed on inactive meters on an annual basis. Ameren Illinois estimates it can reduce at least 90% of residential CIM with the 100% implementation of AMI and associated manual methods.

Over the 20 year business case time horizon, cumulative benefits associated with reduced consumption on inactive meters are estimated at $22 million.

4.8.2. Uncollectible Expense/Bad Debt

Ameren Illinois incurs write-off expenses of approximately $17.8 million per year for electric customer accounts that are deemed to be uncollectible. Due to the manual nature of the existing disconnect for non-pay process, timing of disconnect for non-pay orders, and the existing workload, Ameren Illinois is not able to complete all the physical disconnect for non-pay orders issued in a given year.

AMI meters and infrastructure will be used to perform a remote disconnect and re-connect based on the regulatory timeframe allowed. Ameren Illinois estimates that AMI will help it recover uncollectible expenses through both 1) completing remote disconnects for all non-pay disconnect orders typically issued, and 2) revising collection processes within existing regulations to increase the number of disconnect for non-pay orders issued. Approximately $3.5 million annual reduction in uncollectible expense is estimated after 62% AMI rollout with associated manual methods.

Over the 20 year business case time horizon, cumulative benefits associated with reduced uncollectible expense / bad debt are estimated at approximately $67 million.

4.8.3. **Customer Engagement Benefits**

For the next four customer benefits (Demand Response, Energy Efficiency, Electric Vehicle Enhancement, and Carbon Reduction), Ameren Illinois has scaled the benefits that requires customers to engage in a energy reduction program from the 62% AMI deployment to the 100% deployment, but has not updated the analysis with new baseline assumptions.

4.8.4. **Demand Response**

Once AMI is in place, retail rates can be aligned more closely with the real-time costs of energy. Dynamic pricing and other customer programs are designed to incentivize customers to reduce load during the most expensive hours of the day, thus decreasing the aggregate electricity demand during peak times.

To quantify the potential benefits of Demand Response, Ameren Illinois expects that all Residential customers will be eligible to participate in a Peak Time Rebate program for electricity curtailed during critical peak hours. Residential customers will also have opportunities to opt-in to a Critical Peak Pricing rate with and without enabling technologies, and Direct Load Control or Time-of-Use with smart charging for electric vehicles. Commercial and Industrial customers may be on a Critical Peak Pricing Program, with or without Automated Demand Response. Additionally, certain C&I customers may qualify to participate in a Direct Load Control program. These programs may be provided by the utility or by third party service providers.

The benefits of these programs are largely driven by participation rates in the programs and the change in peak load usage per customer, valued at the appropriate avoided capacity and energy costs and avoided carbon emissions. The cost/benefit analysis assumes a likely participation scenario in which 40% of the residential customers who receive AMI will be on some type of Demand Response (mentioned previously) and 3-6% participation among Commercial and Industrial customers with AMI.

Over the 20 year Business Case time horizon the combined benefits from Demand Response are estimated at $590 million.

4.8.5. **Energy Efficiency**

AMI-enabled Energy Efficiency programs and technologies can contribute to increased Energy Efficiency throughout the day. When customers are more aware of their usage either by using their in-home displays or via the web, they often adjust their behavior and overall energy usage is reduced.

Over the 20 year Business Case time horizon the combined benefits from Energy Efficiency are estimated at $35 million.

4.8.6. Electric Vehicle Enhancement

AMI combined with smart charging technologies will allow PEV owners to charge their vehicles at non-peak times when electricity rates are cheapest. This will lower the PEV cost per mile driven and encourage additional consumers to switch to PEVs (compared to the flat-rate case). Society will benefit from this switch since electricity is cheaper and produces less carbon dioxide per mile driven than gasoline. Assuming that 0.7 percent of vehicles among customers with AMI in the Ameren Illinois territory are PEVs (and assuming furthermore that these PEVS would not have been purchased but for AMI and time-of-use rates that lower the cost of operating these vehicles), the total 20 year Business Case nominal benefit from PEVs is $221 million.

4.8.7. Carbon Reduction

When energy emissions are lowered due to the Energy Efficiency (EE) programs described above, less carbon is emitted. Due to the smart charging of electric vehicles, there would be an increase in off-peak energy usage, emitting more carbon. However, this increase is more than offset by the reduced carbon emissions from avoided gasoline usage in conventional cars. The change in carbon emissions is monetized using the expected price of carbon in the future. Ameren Illinois assumes that the price of carbon will be zero until 2025, at which point it is $30 per metric ton in nominal terms and by 2032 it rises to $51 per metric ton.

The total 20 year Business Case benefits from reduced carbon emissions are $16 million.

4.8.8. Customer Outage Reduction Benefit

AMI facilitates restoring power quicker through the use of the last gasp feature of the meter and the system's ability to ping a meter. Benefits flow to customers in the form of the avoided economic losses they experience due to unreliability. For the purposes of this estimate, various industry reports were reviewed. While the value per customer class did vary slightly and different methods were found in how to value the reliability benefit, there was general consensus that the reliability benefit is an item to be considered when making smart grid investments.

Ameren Illinois utilized the ICE (interruption cost estimation) calculator, which was funded by Lawrence Berkley National Lab and DOE in conjunction with Freeman, Sullivan and Company. The methodology[3] for calculating reliability benefits involved using Ameren Illinois' SAIFI and CAIDI information, survey data from the ICE calculator, and information regarding the number of residential and small commercial customers. Large Commercial and Industrial customers were excluded from the analysis since many of these customers have backup strategies for reliability purposes.

The total 20-year customer value for outage reduction is $35 million.

4.8.9. Additional Customer/Societal Benefits

Additional Customer/Societal Benefits are benefits realized by the broader communities that Ameren Illinois serves. Ameren Illinois has not quantified these benefits at this time.

[3] *The 2011 NARUC report, "Evaluating Smart Grid Reliability Benefits for Illinois"*, January 2011

Safety and Emergency Response

With the implementation of AMI, utilities can more rapidly cooperate with fire departments and other agencies to respond to emergencies. For example, when the local fire department calls to shut down power to a burning home, the utility can quickly respond by remotely disconnecting power via the disconnect switch in the meter.

Furthermore, AMI will also impact employee and vendor safety by eliminating or reducing physical customer premises trips for meter reading, disconnections and other reasons. Safety incidents by field/meters services and meter readers are often a large portion of the overall safety incidents for utilities.

Local Economy

With the rollout of AMI, several jobs will be created during the 8 year field deployment, as well as new skills needed for the back office, communications and IT systems development/maintenance. This will provide a non-trivial impact to the local workforce. Macroeconomic benefits that can enhance the local economy may arise from changes in the expenditure patterns of these workers/consumers.

Market Competition

Competition is fostered on two levels: from a market level and from a supplier component level. With AMI, greater information on energy usage will be available. It is a common belief that the expanded service choices enabled by advanced metering and communication technology are essential if consumers are to realize the full benefits of wholesale competition.[4]

In addition, Ameren Illinois specified the use of standards in choosing its AMI vendor. First, Ameren Illinois' AMI vendor will provide a standards based network that will, in the future, allow other vendors to provide endpoint and network device products that work with the standards based network. At the endpoint, Smart Energy Profile is a key standard to foster interoperability among vendors wanting to offer services in the home energy management area. Using a non-proprietary standard-based HAN solution for the AMI system will prevent vendor "lock-in" and enable more competition for parties desiring to provide solutions.

Other Environmental Benefits

Electricity generation creates the majority of the U.S. sulfur dioxide (SO_2) pollution (primarily from burning coal) and is the second-largest emitter of nitrogen oxides (NOx) after vehicles. As AMI enables utilities to obtain more information and as utilities educate their customers on energy use and choice about using energy, it is expected that more customers will subscribe to various demand management programs. With the AMI-enabled pricing programs, price signals produced via the AMI devices could motivate customers to shift their energy consumption or lower it. This action would smooth out the utility's load curve, thereby reducing the need for high-emission peaking plants in some cases. As customers reduce their peak usage, SO_2 reductions can be achieved thereby eliminating pollution and helping to preserve our environment. Emissions are further reduced by the reduction in vehicle miles driven due to the elimination of manual meter reading and field visits for disconnect / reconnect, stopped meter, and outage investigations.

[4] *Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments,* EPRI report, July 2008

Electric Vehicles

Only the benefits to society of AMI for the additional PEV ownership attributable to AMI were quantified. However, there are still several benefits from AMI that arise from those customers who would have purchased PEVs in the absence of AMI. By incentivizing these PEV owners to charge their vehicles during off-peak periods, AMI will reduce the amount of generation, transmission and distribution capacity needed by Ameren. Furthermore, as battery technology continues to evolve and mature, many believe that the PEVs can be utilized at certain times to provide energy back into the electric grid. AMI's net metering capabilities will be needed to measure the flow of energy in both directions. This is referred to as net metering to determine when the consumer is using power versus supplying. This can potentially be a very valuable resource in integrating more renewable generation resources into the grid.

Distributed Generation

Today, two meters are utilized at a residential level for distributed generation to measure when energy is being consumed from the grid versus when energy is being put out on the grid. With the new AMI meters, one single meter can be utilized in these situations. Net Metering with AMI meters records when consumers are using power versus supplying it. This reduces the costs for both the utility and the customer. Furthermore, with this added net metering functionality, utilities can ubiquitously offer customers new programs for renewable integration without having to add or change equipment. For example, utilities can offer programs around roof-top solar or solar hot water heaters.

Variable Generation

AMI allows for dynamic prices that reflect shifting supply conditions. In doing so, AMI creates an additional tool in managing this variable generation - customer demand response. For example, a smart-charging PEV can help balance the grid at night by charging when the wind gusts and putting additional electricity back on the grid when it does not.

New Services

AMI is a foundational infrastructure that may allow for services that expand into the home for smart appliances. Whirlpool and GE are among some of the leading brands working to integrate smart appliances with AMI. Whirlpool received $19 million in U.S. Department of Energy stimulus funding to support the manufacturing and commercialization of smart appliances that would communicate with AMI over the home area network (HAN). Ameren Illinois intends to purchase AMI meters that are capable of implementing the industry-embraced standard called Smart Energy Profile that governs how third parties interact with the metered information.

Furthermore, utilities can enable programs with customers to reduce load and will now have the capability of monitoring individual customer actions, such as verification that requested load reduction actually takes place

Customer Convenience

With the rollout of AMI, utilities will be able to provide better customer service, especially around customer-directed shut-off and reconnection dates. These improvements in service represent a non-monetary value to the customer, but they generally result in increased levels of customer satisfaction.

Also, for those customers with indoor meters, utilities will no longer have to make arrangements to get access to the building or home to read the meters.

5. Ameren Illinois AMI Cost / Benefit Analysis

For the purposes of comparing the benefits against the costs for the AMI program, Ameren Illinois has developed a robust approach that uses several different evaluation methodologies, including:

- Calculation of Terminal Value
- Payback period
- NPV analysis
- Total Resource Cost (TRC) analysis
- Ratepayer Impact

The timeframe of the primary business case is 20 years for both benefits and costs, which aligns with the estimated useful life for the AMI-related investments.

Terminal value (continuation of benefits and costs beyond 20 years) was also included to reflect the useful life of AMI infrastructure remaining after the 20-year period (due to the staggered rollout schedule). In fact, a signicant portion of Ameren Illinois' AMI meters will have useful life beyond the 20 year investment evaluation.

The cost/benefit analysis is taken from the customer perspective, with costs and benefits modeled as revenue requirement adjustments.

In general, costs are estimated and attributed to the year in which the cost is incurred. Benefits are attributed to the year in which they will be realized, which generally trails the occurrence of the related cost by one year to three years (e.g. customer benefits will be realized the year following the installation of the AMI meters for that portion of the customers).

Included in this analysis are all the benefits and costs across the categories in sections 3 and 4, summarized in Table 20:

Table 20: Benefit & Cost Summary ($ in millions, over 20 years, non-discounted)

Key Cost / Benefit Drivers	Total
Benefits	
Utility O&M Benefits	$570
Utility Capital Benefits	$60
Customer/Societal Benefits	$986
Total (nominal)	**$1,616**
Costs	
Capital	$313
Operations & Maintenance	$207
Total (nominal)	**$510**
Terminal Value in Year 2031	**$456**

From a customer perspective, the impacts of the benefits and costs will take the form of changes to rates and direct customer benefits. Changes to rates are driven by O&M, depreciation, tax and revenue-requirement changes. The following table summarizes the customer benefits.

Table 21: Customer Impact Summary Table ($ in millions, over 20 years, non-discounted)

Net Customer Impact	TOTAL
O&M Expenses Net Change	$362
Depreciation Net Change (including stranded investment in existing meters)	($226)
Taxes Net Change	($39)
Return Requirements Net Change	($84)
Direct Customer Benefits	$1,441
Total (nominal)	**$1,454**

5.1. Calculation of Terminal Value

As Ameren Illinois is planning on an 8 year rollout of AMI meters across 100% of its customers, it is estimating an overall useful life of more than 20 years for the entire AMI system. While it is common practice for AMI business cases to have a 20-year timeframe, Ameren Illinois feels it is prudent to include an estimate of the business case beyond the 20-year window. As stated previously, in 2031 (the last year of the 20-year business case timeframe) approximately 69% of the installed meters will still have a remaining useful life of at least 5 years. It is assumed that the AMI system will still be at critical mass and operating until the number of active meters with remaining depreciable life dips below 100,000.

To capture the business case impacts of the remaining useful life of the AMI-related assets beyond the 20-year business case timeframe, a terminal value analysis was used. This involves using benefit and costs from the final years of the NPV analysis and projecting the future years based on that.

Several key steps are involved in the Terminal Value analysis:

1. Determine when there is no longer critical mass of active meters with remaining depreciable life (at least 100,000 active meters) – 2038
2. Identify the average fixed annual costs for operating and maintaining the AMI system – $7 million
3. Identify the average variable annual net benefit per meter (total benefits - variable costs) – $103.56
4. Calculate the net impact by year for each year remaining on useful life of meters up to the point where there is not critical mass of the AMI system (from 1.2M meters in service in 2032 to 250,000 meters in service in 2038)
5. Calculate the NPV of these net impacts using the customer-relevant discount rate of 5.583% (Weighted Average Cost of Capital) to get the Terminal Value in 2032
6. Discount the 2032 Terminal Value to 2012 using the same discount rate

This results in a terminal value in 2032 of $456 million. By discounting this back to 2012, the terminal value yields an additional present value $154 million:

Table 22: Terminal value result ($ in millions)

Result	Total
NPV of Terminal Value in 2031	$456
NPV of Terminal Value in 2012	$154

5.2. Payback Period

The first business case methodology used by Ameren Illinois is the payback period analysis. This involves calculating when the cumulative customer benefits equals and begins to exceed the cumulative customer cost stream. This is useful in understanding to what extent the realization of the benefits lag the incurrence of the costs.

Below is a summary of the benefit & cost cash flows along with the cumulative cash flow:

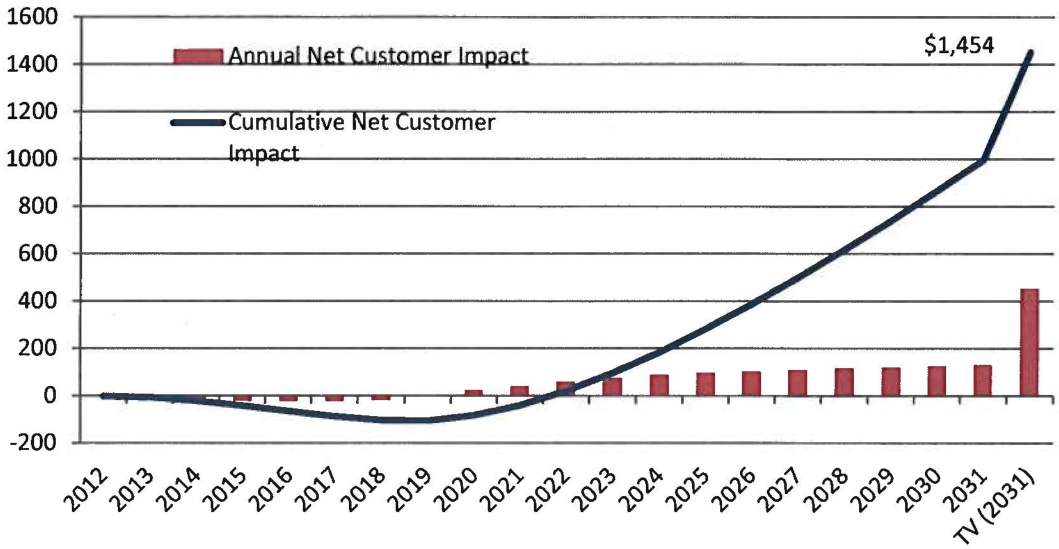
Table 23: Annual & Cumulative Cost / Benefit Cash Flow (in $ millions, non-discounted)

Year	Annual Net Customer Impact	Cumulative Net Customer Impact
2012	(1)	(1)
2013	(5)	(6)
2014	(14)	(20)
2015	(21)	(41)
2016	(23)	(64)
2017	(21)	(85)
2018	(17)	(102)
2019	(3)	(105)
2020	24	(81)
2021	41	(40)
2022	61	21
2023	76	97
2024	89	186
2025	99	285
2026	104	389
2027	111	500
2028	118	618
2029	122	740
2030	127	867
2031	131	998
Terminal Value (2031)	456	1,454

As can be seen in the table above, the payback period for the AMI business case is 11 years. In other words, the cumulative benefits will begin to exceed the cumulative costs in 2022. This payback period is reasonable, especially given the following factors:

- The bulk of the capital investment is in the first six years of the project duration
- The need to maintain multiple meter reading capabilities (processes & technologies) during the rollout period (manual read, AMR, and AMI during first seven years; AMR and AMI during the remaining years)
- The rollout of the meters is over an 8 year period, with 100% of the meters deployed by 2019.

Figure 3: Payback Summary ($ millions)



5.3. Net Present Value

The second methodology used to evaluate the AMI business case is a Net Present Value (NPV) analysis. In this analysis, the annual costs and benefits cash flows of the AMI program are discounted by a customer-relevant discount rate. Ameren Illinois has taken a conservative approach to the relevant discount rate and used its current Weighted Average Cost of Capital (WACC) as the discount rate. This results in an estimate of the economic value of the investment.

In this analysis, any NPV of greater than zero signifies an investment that earns a positive financial return after accounting for the time-value of money.

Below is a summary of the discounted net benefit/cost per year:

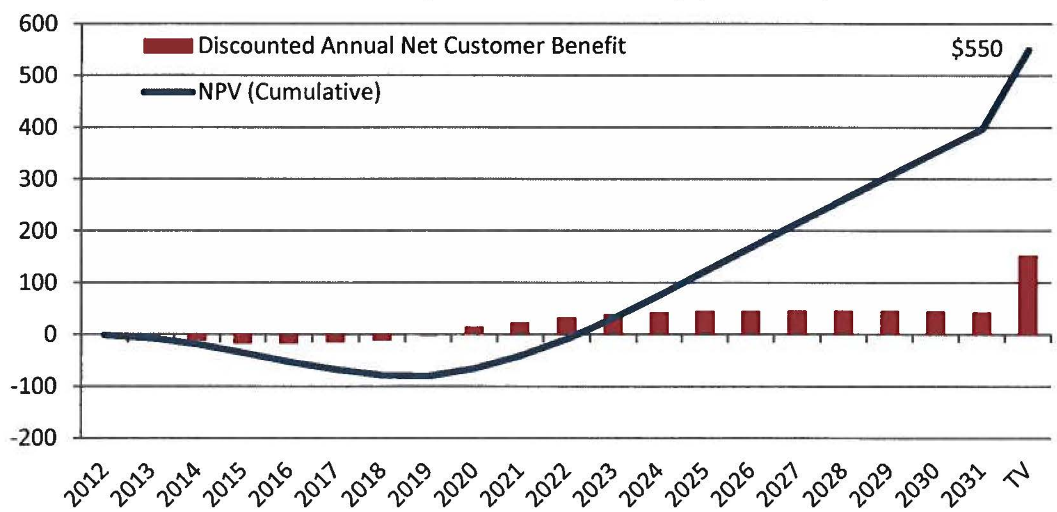
Table 24: Annual Discounted Net Customer Benefit (in $ millions, discounted)

Year	Net Customer Benefit
2012	(1)
2013	(5)
2014	(12)
2015	(17)
2016	(17)
2017	(15)
2018	(11)
2019	(2)
2020	15
2021	24
2022	33
2023	40

Year	Net Customer Benefit
2024	44
2025	46
2026	46
2027	47
2028	47
2029	46
2030	45
2031	44
TV (Terminal Value)	154
TOTAL (NPV)	**550**

As seen above, the NPV for the AMI business case is $550 million.

Figure 4: NPV Summary ($ millions)



5.4. Total Resource Costs (TRC)

Ameren Illinois also used a Total Resource Costs (TRC) analysis, which is a comparison of the total costs of the project (from both the utility and customer perspective) with the total benefits of the project (again, from both the utility and customer perspective).

Similar to the NPV analysis, both the benefits and costs are discounted to a net present value using a customer-relevant discount rate. Ameren Illinois has taken a conservative approach to the societal cost of money and used its current Weighted Average Cost of Capital (WACC) as the discount rate. The TRC is then calculated as ratio of the present value of benefits to the present value of costs.

For the purposes of this analysis, several simplifying assumptions were used in calculating the TRC. Specifically, Ameren Illinois used the net O&M and capital impacts as inputs into this analysis. Ameren Illinois considered net impacts that are negative as costs and net impacts that are positive as benefits. Terminal value was included as a net benefit in the Gross Resource Benefits.

The result of the TRC analysis is a TRC of 2.70, which is summarized in Table 25.

Table 25: Total Resource Costs Analysis Summary ($ in millions, over 20 years)

Category	TOTAL
Gross Resource Benefits (nominal)	$2,011
PV of Gross Resource Benefits	$874
Gross Resource Costs (nominal)	$548
PV of Gross Resource Costs	$324
Total Resource Costs (ratio of PV of Gross Resource Benefits to PV of Gross Resource Costs)	**2.70**

5.5. Ratepayer Impact

The final methodology used to analyze the costs and benefits of Ameren Illinois' 100% AMI deployment is the ratepayer impact test. The ratepayer impact test takes the net Total Cost to Customers and multiplies it by the number of annual bills for a rate class and the percentage of the revenue requirement that customer class receives. The ratepayer impact test assumes that the AMI investment will impact revenue requirement in relative proportion to "customer-related" costs in the electric class cost of service study (ECOSS) today. The "customer-related" costs Ameren Illinois included in this analysis are all costs and the O&M and Capital benefits that flow through the revenue requirement as well as the consumption on inactive meter and uncollectible benefits under the Customer benefits classification. From the latest ECOSS study, 73.6% of the incremental revenue requirement is within the residential class, and 22.3% is within the DS-2 small non-residential class.

The result of the AMI investment's impact on a customer's monthly delivery services bills is summarized in the following table.

Table 26: Ratepayer Impact Test Summary ($ in millions, over 20 years)

Year	DS-1 Residential Customer	DS-2 Small Non-Residential Customer
2012	$ 0.03	$ 0.07
2013	$ 0.31	$ 0.67
2014	$ 0.80	$ 1.74
2015	$ 1.21	$ 2.63
2016	$ 1.37	$ 2.98
2017	$ 1.37	$ 2.98
2018	$ 1.36	$ 2.95
2019	$ 1.08	$ 2.35
2020	$ 0.23	$ 0.50

Year	DS-1 Residential Customer	DS-2 Small Non-Residential Customer
2021	$(0.10)	$(0.22)
2022	$(0.47)	$(1.01)
2023	$(0.77)	$(1.67)
2024	$(1.06)	$(2.30)
2025	$(1.17)	$(2.54)
2026	$(1.21)	$(2.64)
2027	$(1.54)	$(3.34)
2028	$(1.70)	$(3.69)
2029	$(1.82)	$(3.95)
2030	$(1.90)	$(4.13)
2031	$(1.97)	$(4.28)

The ratepayer impact analysis includes two of the seven Customer benefits listed in Table12 (Consumption on Inactive Meter - $22 million and Uncollectibles - $67 million). The Customer Engagement benefits (Demand Response - $590 million, Energy Efficiency - $35 milliion , Electric Vehicle Enhancement - $221 million, and Carbon Reduction - $16 million) plus the Value of Reduced Outage Duration - $35 million are not included since they would flow to customers from energy usage reductions or economic loss avoided and not through a customer's delivery services rate.

6. Sensitivity Analysis

Ameren Illinois acknowledges that despite a meticulous and data-driven approach to conducting the cost / benefit analysis, the longer-term nature of the business case implies inherent uncertainties in the estimates of several AMI cost and benefit drivers. Ameren Illinois has thus conducted sensitivity analysis to identify the impact of changes to certain drivers on the base case.

6.1. Approach and Assumptions

Outlined in Table 27 is a summary of all the cost and benefit drivers that were subjected to sensitivity analysis. The table also highlights the range of values that each sensitivity parameters was subjected to and the change in Internal Rate of Return (IRR) from the base case. The base case Internal Rate of Return is 28.4%.

Table 27: Sensitivity Analysis Variables, Assumptions, and Impact on IRR

Sensitivity Variable	Base Case Value	Sensitivity Range / Assumptions	Description / Rationale	New IRR
Customer Engagement in AMI Enabled Programs	Included	Excluded	Ameren Illinois has included benefits that requires the customer to engage in an energy saving program enable by AMI such as energy efficiency, demand response, or electric vehicle charging.	12.7%
Customer/ Societal (DR,EE,& PEV)	40% participation rate	20% - 60% participation rates	Ameren Illinois has conducted analysis around Customer/Societal benefits and assumed 40% participation rate by customers in the base case. For the purposes of the sensitivity analysis, Ameren Illinois has taken 50% to 150% of this value.	22.5% - 32.8%
Energy Theft Reduction	0.25%	0.1% - 0.4%	The model estimates that AMI will help Ameren Illinois save 0.25% of revenue associated with each AMI meter that is currently lost due to energy theft. Ameren Illinois has observed that other utilities have seen energy theft reduction benefits in the range of 0.5% - 1% of revenue. For the purposes of the sensitivity analysis, Ameren Illinois estimates (again, conservatively) that between 0.1% and 0.4% of revenue associated with each AMI meter can be saved as a result of AMI.	28.0% - 28.9%
CIM Benefits ($ per KWH Recovery)	9.79 cents / KWH	5.39 cents / KWH	In the base case, Ameren Illinois assumes that it will be able to bill for and thereby recover the full 9.79 cents / KWH for consumption on inactive meters once AMI is implemented For purposes of sensitivity analysis, Ameren Illinois assumes that even if there is no tenant to bill for the entire lost energy consumption, it could still save energy supply cost of 5.39 cents / KWH.	28.2%

Sensitivity Variable	Base Case Value	Sensitivity Range / Assumptions	Description / Rationale	New IRR
Uncollectible Benefits	$3.75 million per year after 10 years of AMI rollout	-15% to +15%[5]	For the base case, Ameren Illinois assumes that at 100% AMI rollout, it will be able to reduce uncollectible electric expense by approximately 20%. Since the ability to reduce bad debt expense depends on a multitude of factors including recovery rate after disconnect and increase in recoverable amount through revised collection process, Ameren Illinois estimates a 30% decrease and a 15% increase in uncollectible benefits for the purposes of sensitivity analysis.	28.2% - 28.7%
O&M Benefits	$557 million	-10% to +10%	Ameren Illinois' projected O&M benefits are driven by a data-focused and rigorous approach to estimations around cost reductions and loss prevention in numerous areas such as meter reading, field & meter services, UFE, billing and customer management etc. However, despite the analytical approach, unforeseen circumstances may cause the projected O&M benefits to vary. In order to calculate a range for the O&M benefits, Ameren Illinois assumes a 10% decrease and a 10% increase in O&M benefits over the 20-year business case time horizon.	27.0% - 29.8%
O&M Costs	$236 million	10% Increase	Ameren Illinois' projected O&M costs are based on a comprehensive assessment of the various drivers and associated yearly costs to operate and maintain the AMI infrastructure. However, due to the long-term nature of the AMI deployment, certain costs such as those to operate and maintain the AMI Communications Network as well as IT-related labor software maintenance costs may vary. Thus, Ameren Illinois assumes a 10% increase in O&M costs for purposes of sensitivity analysis	27.4%

Sensitivity Variable	Base Case Value	Sensitivity Range / Assumptions	Description / Rationale	New IRR
Capital Costs	$314 million	5% Increase	Ameren Illinois' projected capital costs for meters and communications network hardware are based on contracted pricing obtained in a rigorous vendor sourcing process. Capital costs for IT systems and labor, and management labor for the most part have already been deployed. Ameren Illinois thus assumes a 5% increase in capital costs for the purposes of sensitivity analysis	27.8%

6.2. Sensitivity Analysis Results

If all of the sensitivities are adjusted to the most conservative view, the AMI implementation still returns a 6.62% internal rate of return to Ameren Illinois' customers. The most conservative view still exceeds the weighted average cost of capital of 5.583%.

7. Appendix

7.1. General Assumptions

- The business case assumes 100% deployment of AMI electric meters over a period of 8 years
- The model analysis period is 20 years starting in 2012, ending in 2031, with AMI meter deployment commencing in year 2014
- Meter depreciation time (useful life) period used in the model is 20 years
- Meter growth rate is estimated at 0.0% annually
- Salvage cost per meter is assumed to be $0.65
- The following escalation rates over the 20-year business case time horizon are assumed:
    - General: 2.0%
    - Labor: 2.5%
    - Transportation: 2.0%
- Financial Assumptions
    - AIC composite tax rate of 40.0% is used to calculate Net Customer Impact
    - Discount Rate of 5.563% (Ameren Illinois' Weighted Average Cost of Capital) is used to calculate NPV and TRC

7.2. Cost Summary by Year (in $ millions)

	20-Year Total	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital Items - Summary																					
Meters																					
AMI Electric Meters	157.9	-	-	8.0	25.2	18.5	39.0	36.4	30.8	-	-	-	-	-	-	-	-	-	-	-	-
AMI Electric Meter Installation	37.8	-	-	1.1	3.8	5.4	9.6	9.7	8.2	-	-	-	-	-	-	-	-	-	-	-	-
Communication Network																					
AMI Communications Equipment	17.7	-	1.0	4.1	3.1	5.5	0.9	-	-	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AMI Communications Equipment Installation	4.2	-	-	0.3	0.7	1.7	0.7	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Make Ready Distribution Work	7.7	-	-	1.4	0.9	2.3	1.6	1.5	0.0	-	-	-	-	-	-	-	-	-	-	-	-
Information Technology (Applications and Operations)																					
Hardware	11.8	-	2.1	0.2	0.2	0.0	0.1	0.1	1.0	3.7	-	-	-	-	-	4.4	-	-	-	-	-
Software	4.8	-	3.2	1.1	0.2	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-
Labor	35.6	-	10.2	14.3	10.5	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Integrated Operations Center	2.8	-	0.8	1.0	0.2	0.2	0.2	0.2	0.2	-	-	-	-	-	-	-	-	-	-	-	-
Program Management																					
Program Management	9.7	2.9	0.4	0.7	1.1	1.2	1.1	1.1	1.2	-	-	-	-	-	-	-	-	-	-	-	-
AMI Operations Support of Deployment																					
Metering	4.6	-	-	-	0.1	1.1	1.2	1.2	1.0	-	-	-	-	-	-	-	-	-	-	-	-
Communications	2.6	-	-	0.0	0.1	0.7	0.7	0.6	0.4	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous (Contingency)	16.0	-	0.3	0.8	0.0	0.0	4.9	5.1	4.8	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	313.2	2.9	18.1	32.9	46.1	37.4	60.0	56.5	47.9	3.8	0.1	0.3	0.3	0.3	0.3	4.7	0.3	0.3	0.3	0.3	0.3
O&M Items - Summary																					
Meter Reading Costs																					
Manual Disconnect & Read to Meet Metrics	1.4	-	-	0.5	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Communications Network	12.3	-	-	0.2	0.3	0.8	0.6	0.6	0.7	0.8	1.6	0.4	0.1	0.1	0.9	1.7	0.4	0.1	0.1	0.9	1.9
Accelerated Depreciation for Existing Meters	1.0	-	-	0.4	1.4	2.5	4.1	5.0	5.3	3.4	1.7	(0.8)	(3.0)	(4.2)	(3.6)	(3.0)	(2.5)	(2.0)	(1.6)	(1.2)	(0.9)
Electric Meter & Gas Module (Failures)	2.0	-	-	-	-	0.1	0.1	0.2	0.3	0.4	0.3	0.3	0.2	0.1	-	-	-	-	-	-	-
Information Technology (Applications and Operations)																					
Hardware	4.0	-	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Software	28.4	0.0	0.6	0.5	0.4	0.9	1.0	1.3	1.7	1.8	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9
Labor	58.7	0.1	0.8	0.8	1.9	2.9	2.9	2.7	3.0	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.1
Integrated Operations Center	21.9	-	-	0.8	0.6	0.8	0.7	0.8	1.0	1.3	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6
Asset Management	1.8	-	-	-	-	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Management and Other Costs																					
Program Management	0.5	-	-	-	-	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-
Metering Operations	0.2	-	-	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-
Change Management	1.6	-	-	0.7	0.4	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-
AMR Termination Fee	7.1	-	-	-	-	-	-	3.3	3.8	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous	0.0	-	-	-	-	-	-	-	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
Customer Education - Deployment & Initial Functionality	8.2	-	0.3	1.3	1.1	1.0	1.5	1.5	1.5	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	4.9	-	-	-	-	0.1	0.2	0.3	0.6	0.7	0.5	0.6	0.6	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0
Energy Efficiency	4.9	-	-	-	-	0.1	0.2	0.3	0.6	0.7	0.5	0.6	0.6	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0
Electric Vehicle Enhancement	25.3	-	-	-	-	0.5	0.8	1.7	2.9	3.3	2.9	3.1	3.2	2.5	1.9	1.4	0.7	0.1	0.1	0.0	0.0
Customer Technology Interface & Support	23.0	-	-	-	-	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.2	0.2	0.2	0.2	0.2
Total O&M	207.3	0.1	1.8	5.2	6.7	12.5	14.9	20.5	23.9	17.9	16.2	12.9	10.6	8.4	9.0	10.0	6.6	6.1	6.6	8.0	9.4
Grand Total O&M / Capital	520.5	2.9	19.9	38.1	52.8	49.9	74.9	77.1	71.7	21.7	16.4	13.2	10.9	8.7	9.4	14.7	6.9	6.4	6.9	8.3	9.7

7.3. Benefits Summary by Year (in $ millions)

	20-Year Total	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
O&M Items - Summary																					
Meter Reading																					
Reduction in Manual Meter Reading Expenses	119.6	-	-	-	-	3.1	5.1	6.7	6.9	7.1	7.3	7.4	7.6	7.8	8.0	8.2	8.4	8.6	8.9	9.1	9.3
Reduction in AMR Meter Reading Expenses	140.0	-	-	0.4	0.4	0.4	0.8	3.0	6.9	9.5	9.7	9.9	10.1	10.3	10.5	10.8	11.0	11.2	11.4	11.7	11.9
Reduction in Manual and AMR Meter IT Costs	1.8	-	-	-	-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Reduction in On-Cycle Meter Reading Vehicle	1.2	-	-	-	-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Field & Meter Services																					
Reduction in Manual Disconnect / Reconnect Meters	147.2	-	-	-	0.4	2.0	3.7	5.9	8.1	9.2	9.4	9.7	9.9	10.2	10.4	10.7	10.9	11.2	11.5	11.8	12.1
Reduction in Manual Off-Cycle / Special Meter Reads	39.7	-	-	-	0.2	1.1	1.8	2.2	2.3	2.3	2.4	2.4	2.5	2.6	2.6	2.7	2.8	2.8	2.9	3.0	3.1
Reduction in Nuisance Stopped Meter Orders	2.9	-	-	-	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Reduction in Field Services Vehicle Expense	29.7	-	-	-	0.1	0.5	0.9	1.3	1.7	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.3
Reduction in Customer Equipment Problem Outage Field Tri	3.5	-	-	-	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Reduction in "OK on Arrival" Outage Field Trips	17.8	-	-	-	0.1	0.2	0.4	0.7	1.0	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5
Salvage Value of Replaced Meters	1.0	-	-	0.0	0.1	0.2	0.2	0.2	0.2	-	-	-	-	-	-	-	-	-	-	-	-
Reduction in Unaccounted for Energy																					
Theft / Tamper Detection & Reduction	32.1	-	-	-	-	0.2	0.9	1.4	1.9	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5
Faster Identification of Dead Meters	2.6	-	-	-	-	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Customer Care Improvements																					
Customer Service Support of AMI Implementation	1.2	-	0.1	0.4	0.6	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reduction in Call Volume	9.6	-	-	-	-	0.1	0.3	0.4	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8
Reduction in Float Between Meter Read & Customer Billing	0.6	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reduction in Customer Accounts Management	1.2	-	-	-	-	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Information Technology (Applications and Operations)																					
Information Technology	3.5	-	-	-	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Distribution Network Efficiencies																					
Distribution System Management	1.5	-	-	-	-	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Outage Management	7.8	-	-	-	-	0.1	0.2	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Asset Management Planning	5.2	-	-	-	-	0.0	0.1	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total O&M Impacts	569.6	-	0.1	0.8	2.0	8.3	15.1	23.4	31.2	35.9	36.7	37.5	38.4	39.2	40.1	41.1	42.0	43.0	43.9	45.0	46.0
Capital Items - Summary																					
Distribution System Management	13.4	-	-	-	-	0.2	0.4	0.6	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1
Outage Management	11.6	-	-	-	-	0.2	0.3	0.5	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0
Asset Management Planning	9.1	-	-	-	-	0.1	0.2	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8
Avoided Meter Purchases	26.2	-	-	0.2	0.7	1.3	2.0	2.0	2.1	2.1	2.0	1.9	1.6	1.4	1.2	1.2	1.2	1.3	1.3	1.4	1.4
Total Capital Impacts	60.3	-	-	0.2	0.7	1.8	2.9	3.4	3.9	4.2	4.2	4.1	3.9	3.7	3.6	3.7	3.8	3.9	4.0	4.1	4.2
Customer Benefits																					
Consumption on Inactive Meters	22.3	-	-	-	-	0.3	0.4	0.7	1.2	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8
Uncollectible Expense	67.2	-	-	-	-	0.9	1.8	2.8	3.8	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4
Demand Response	589.6	-	-	-	-	0.3	1.0	3.4	9.0	17.7	25.1	34.4	41.5	47.1	51.5	55.0	56.0	58.5	60.8	63.0	65.3
Energy Efficiency	35.0	-	-	-	-	0.0	0.1	0.3	0.6	1.1	1.6	2.2	2.7	3.0	3.2	3.3	3.3	3.3	3.4	3.4	3.4
Electric Vehicle Enhancement	220.6	-	-	-	-	0.2	0.6	1.8	4.1	7.1	10.0	13.5	16.1	18.0	19.5	20.6	20.7	21.3	21.9	22.3	22.9
Carbon Reduction	15.5	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6	1.8	2.0	2.2	2.4	2.6	2.7
Value of Reduced Outage Duration	35.4	-	-	-	-	0.2	0.9	1.4	2.0	2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.9	2.9
Total Customer Impacts	985.6	-	-	-	-	2.0	4.7	10.4	20.7	33.9	44.9	58.5	68.8	77.0	84.8	89.9	91.3	94.9	98.2	101.3	104.5
Grand Total	1,615.6	-	0.1	0.9	2.7	12.1	22.6	37.2	55.8	74.0	85.8	100.2	111.1	119.9	128.5	134.6	137.1	141.8	146.1	150.3	154.7

7.4. Net Customer Impacts Summary by Year (in $ millions)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
O&M Benefits																				
Total AMI O&M Savings	-	0.1	0.8	2.0	8.3	15.1	23.4	31.2	35.9	36.7	37.5	38.4	39.2	40.1	41.1	42.0	43.0	43.9	45.0	46.0
O&M Expenses																				
Meters and Modules	-	-	(1.0)	(2.0)	(3.7)	(5.1)	(5.8)	(6.3)	(4.7)	(3.7)	0.2	2.7	4.0	2.7	1.3	2.1	1.9	1.5	0.2	(1.0)
Information Technology Applications and Operations	(0.1)	(1.5)	(2.2)	(3.1)	(4.8)	(4.8)	(5.2)	(6.0)	(6.5)	(6.6)	(6.7)	(6.9)	(7.0)	(7.2)	(7.3)	(7.5)	(7.6)	(7.8)	(7.9)	(8.1)
Management and Other Costs	-	(0.3)	(2.0)	(1.5)	(4.0)	(5.0)	(9.6)	(11.6)	(6.7)	(5.9)	(6.3)	(6.4)	(5.4)	(4.6)	(4.0)	(1.2)	(0.4)	(0.3)	(0.2)	(0.3)
Total AMI O&M Expense	(0.1)	(1.8)	(5.2)	(6.7)	(12.5)	(14.9)	(20.5)	(23.9)	(17.9)	(16.2)	(12.9)	(10.6)	(8.4)	(9.0)	(10.0)	(6.6)	(6.1)	(6.6)	(8.0)	(9.4)
Depreciation / Taxes and Total Costs to Customers																				
Net Change in Operation and Maintenance Expense	(0.1)	(1.7)	(4.4)	(4.8)	(4.2)	0.2	2.8	7.3	18.0	20.5	24.6	27.8	30.8	31.1	31.1	35.4	36.9	37.3	37.0	36.6
Net Change in Book Depreciation	(0.3)	(2.2)	(5.9)	(10.1)	(13.3)	(15.7)	(16.9)	(16.4)	(14.8)	(13.5)	(13.0)	(12.4)	(12.0)	(11.8)	(11.9)	(12.0)	(11.8)	(11.3)	(10.6)	(10.0)
Net Change in Income Taxes	(0.1)	(0.5)	(1.1)	(1.9)	(2.3)	(3.3)	(4.1)	(4.7)	(4.1)	(3.5)	(3.0)	(2.6)	(2.2)	(1.8)	(1.5)	(1.1)	(0.8)	(0.5)	(0.2)	0.1
Net Change in Return Requirement	(0.1)	(1.0)	(2.4)	(4.1)	(5.0)	(7.1)	(8.8)	(10.0)	(8.8)	(7.6)	(6.5)	(5.6)	(4.7)	(3.8)	(3.2)	(2.4)	(1.7)	(1.0)	(0.4)	0.1
Total Cost to Customers	(0.6)	(5.3)	(13.8)	(20.9)	(24.9)	(25.9)	(27.0)	(23.7)	(9.8)	(4.2)	2.0	7.2	12.0	13.8	14.5	19.9	22.6	24.5	25.8	26.9
Customer Benefits																				
Consumption on Inactive Meters	-	-	-	-	0.3	0.4	0.7	1.2	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8
Uncollectible Expense	-	-	-	-	0.9	1.8	2.8	3.8	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4
Demand Response	-	-	-	-	0.3	1.0	3.4	9.0	17.7	25.1	34.4	41.5	47.1	51.5	55.0	56.0	58.5	60.8	63.0	65.3
Energy Efficiency	-	-	-	-	0.0	0.1	0.3	0.6	1.1	1.6	2.2	2.7	3.0	3.2	3.3	3.3	3.3	3.4	3.4	3.4
Electric Vehicle Enhancement	-	-	-	-	0.2	0.6	1.8	4.1	7.1	10.0	13.5	16.1	18.0	19.5	20.6	20.7	21.3	21.9	22.3	22.9
Carbon Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6	1.8	2.0	2.2	2.4	2.6	2.7
Customer Outage Benefits	-	-	-	-	0.2	0.9	1.4	2.0	2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.9	2.9
Terminal Value	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	455.7
Total Customer Benefits	-	-	-	-	2.0	4.7	10.4	20.7	33.9	44.9	58.5	68.8	77.0	84.8	89.9	91.3	94.9	98.2	101.3	560.2
Net Customer Impact (Change in Customer Costs)	(0.6)	(5.3)	(13.8)	(20.9)	(22.9)	(21.2)	(16.6)	(3.0)	24.1	40.7	60.6	75.9	89.0	98.6	104.4	111.2	117.5	122.7	127.0	587.0
Cumulative Net Customer Impact	(0.6)	(5.9)	(19.7)	(40.6)	(63.5)	(84.7)	(101.3)	(104.3)	(80.2)	(39.5)	21.1	97.0	186.0	284.5	388.9	500.1	617.7	740.3	867.4	1,454.4
Net Present Value of Net Customer Impact	550.3																			
INTERNAL RATE OF RETURN	28.4%																			

7.5. Total Resource Costs (TRC) and Ratepayer Impact Test Analyses by Year

(In $ Millions, except TRC ratio and Average Cost Per Month)

TOTAL RESOURCE COST ANALYSIS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Customer Benefits (non-discounted)	-	0.1	0.8	2.0	10.3	19.8	33.7	51.9	69.8	81.6	96.0	107.1	116.2	124.9	130.9	133.3	137.9	142.1	146.2	606.3
Total Customer Benefits (discounted)	-	0.1	0.7	1.6	7.8	14.3	23.1	33.6	42.8	47.4	52.8	55.8	57.3	58.4	58.0	55.9	54.8	53.5	52.1	204.5
NPV of Customer Benefits	874.4																			
Total Customer Costs (non-discounted)	(0.6)	(5.4)	(14.6)	(22.9)	(33.2)	(40.9)	(50.3)	(54.9)	(45.6)	(40.9)	(35.5)	(31.2)	(27.2)	(26.4)	(26.6)	(22.1)	(20.4)	(19.4)	(19.2)	(19.2)
Total Customer Costs (discounted)	(0.5)	(4.8)	(12.4)	(18.4)	(25.3)	(29.6)	(34.4)	(35.5)	(28.0)	(23.7)	(19.5)	(16.3)	(13.4)	(12.3)	(11.8)	(9.3)	(8.1)	(7.3)	(6.8)	(6.5)
NPV of Customer Costs	(324.1)																			
Total Resource Costs	2.70																			

RATEPAYER IMPACT TEST	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Average Cost per Month per Residential Customer	$ 0.03	$ 0.31	$ 0.80	$ 1.21	$ 1.37	$ 1.37	$ 1.36	$ 1.08	$ 0.23	$(0.10)	$(0.47)	$(0.77)	$(1.06)	$(1.17)	$(1.21)	$(1.54)	$(1.70)	$(1.82)	$(1.90)	$ (1.97)
Average Cost per Month per Small Non-Residential Customer	$ 0.07	$ 0.67	$ 1.74	$ 2.63	$ 2.98	$ 2.98	$ 2.95	$ 2.35	$ 0.50	$(0.22)	$(1.01)	$(1.67)	$(2.30)	$(2.54)	$(2.64)	$(3.34)	$(3.69)	$(3.95)	$(4.13)	$ (4.28)

	Annual Bills (in Millions)	% of Revenue Requirement
DS-1 Residential	12.7	73.6%
DS-2 Small Non-Residential	1.8	22.3%

7.6. Terminal Value Summary

(in $)

	5-Year Average 2027 - 2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Number of Meters Installed	1,248,453	1,248,453	1,248,453	1,202,107	1,040,540	861,641	555,904	250,167	-	-	-	-	-	-	-	-
AMI System Still at Scale? *(designates whether there are at least 100,000 meters installed)*		Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No	No
Total AMI O&M Annual Expense	(7,324,946)	(7,471,445)	(7,620,874)	(7,773,292)	(7,928,758)	(8,087,333)	(8,249,079)	(8,414,061)	-	-	-	-	-	-	-	-
Total Net Customer Impact (Change in Customer Costs)	121,966,114															
Total Net Customer Impact Without O&M Annual Expense	129,291,061															
Average Per Meter Net Customer Impact Without O&M Annual Expense *(assumes benefit declines 100% to 50% on straight-line basis)*	103.56	100.11	96.66	93.20	89.75	86.30	82.85	79.40	-	-	-	-	-	-	-	-
Calculated Net Customer Impact (Change in Customer Costs)		117,509,913	113,050,782	104,268,988	85,462,704	66,273,015	37,806,907	11,448,393	-	-	-	-	-	-	-	-
NPV of Terminal Value in 2031	$ 455,691,100															

Revenue Assurance

Smart Meters help utilities reduce what they call "unaccounted-for losses." "Lost" electricity is electricity generated and distributed, but not billed, to customers. Traditional cost-based ratemaking includes such losses in customer rates. (To understand the mechanics, interested readers are encouraged to review the discussion on traditional ratemaking in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.)

Lost revenues result from three primary sources: metering errors, theft, and line losses. Here we will address how Smart Meters defend against metering errors and theft.

	Economic	Reliability	Environmental	Customer Choice
Revenue Assurance Benefits (Reference Case and Ideal Case)	$3.00 per year			

Revenue Assurance Description and Value Creation

Smart Meters are both much more accurate than traditional mechanical meters and offer theft detection capabilities unavailable in traditional meters. We will address these capabilities individually.

Meter Accuracy

State regulators generally prescribe the minimum accuracy standards for meters for the investor-owned utilities they regulate, typically within 2 percent (high or low) of actual electric current flow. A study by the Ohio Public Utilities Commission of Duke Energy's Ohio Smart Meter deployment found that the analog meters being replaced were accurate to within 0.53 percent of actual use.[38] Manufacturers of most Smart Meters warrant accuracy to within 0.5 percent of actual use, a four-fold increase in accuracy over most states' regulatory rules. The Ohio PUC study found Smart Meters to be accurate to within 0.167 percent,[39] a threefold increase in accuracy over the old analog meters. Additionally, this study found that traditional meters were much more likely to be slow than Smart Meters. A customer with a slow meter is charged for less electricity than he or she is actually using. All other customers make up for these customers' underpayments in the form of slightly higher rates.

38 "Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 21.

39 Ibid.

ATTORNEY GENERAL
EXHIBIT 9

Theft Detection

All customers pay the price for electricity theft in the form of higher rates. Smart Meters can help utilities identify electricity theft and catch it earlier, to the benefit of all customers. Each Smart Meter is equipped with sensors alerting the utility to meter removal – even if it is only momentary – or to the presence of magnets, both of which are not detected by traditional meters. However, the sensors do not help in cases in which a meter is completely bypassed. This is where Smart Meters' capability to measure when power is used can help.

Most customers who steal electricity through meter bypass (literally, with wires) do so on a temporary basis. For example, they might only bypass the meter for three weeks out of every four, allowing some usage to register so as not to raise utility suspicion. These customers simply repeat the on-off bypass pattern each month. Traditional meters, which only count the spins of the dial since the last meter read, cannot catch this type of activity. However, utilities with Smart Meters are developing and applying review algorithms to detect such patterns in the detailed usage data Smart Meters offer.

Economic Benefits of Revenue Assurance

The total revenue assurance economic benefit amounts to $3.00 per customer per year, consisting of $1.56 in meter accuracy[40] and $1.44 in theft detection benefits.[41] Of note, the theft detection benefit is net of detection and prosecution costs.

Drivers of Revenue Assurance Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Revenue Assurance	X			X

It is likely that the greater the average age of the traditional meters that are replaced, the greater the improvement in accuracy and the greater the resultant benefit. In addition, electric rates have an impact. The higher the price per unit of use, the greater the resulting underbillings for a given level of meter error will be. Ohio electric rates are about average compared to the rest of the U.S.[42]

We make no distinction between the Reference Case and the Ideal Case for the revenue assurance benefit, as clear drivers such as customer participation rates are not available to use as a basis for distinguishing between them.

40 $1.07 million in annual revenue divided by 685,859 customers. Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 85.

41 $990,000 annual benefit divided by 685,859 customers. Ibid, 82.

42 Ohio is in the middle quintile, with 40 percent of states reporting higher rates, and 40 percent reporting lower rates. U.S. Energy Information Administration, "Table 5A. Residential Average Monthly Bill by Census Division, and State 2011," Line 66 (U.S. Total), Column D ("Price").

Customer Energy Management

A traditional electric bill indicates how much electricity a customer uses over a month. Smart Meters record how much electricity a customer uses every 10 or 15 minutes, information that many utilities make available to customers so that they can better manage and reduce their electric use.

	Economic	Reliability	Environmental	Customer Choice
Customer Energy Management Benefits	\$0.77–1.92 per year		14–34 lbs. CO_2e/year	YES

Customer Energy Management Description and Value Creation

Many customers have had access to electric bill histories via a secure utility web page for some time. Some utilities even provide comparisons to anonymous neighbors' historical usage data to help customers benchmark their usage. However, the detailed information from Smart Meters takes the concept of energy usage feedback to a whole new level.

Smart Meters enable utilities to provide access to detailed historical usage data (in 10- or 15-minute intervals) and/or real-time usage data. Most utilities installing Smart Meters offer customers access to detailed historical usage data via a secure Internet website or a smartphone application, generally on a one-day lag. Some utilities also offer their customers access to real-time data via an in-home display, web portal, or smartphone app. This latter capability, in particular, has a demonstrated impact on electricity consumption by providing customers with immediate feedback on their usage and the impact of changes they make to their usage.

Economic Benefits of Customer Energy Management

A survey of electric usage display impact research in Canada found an average 7 percent conservation effect.[43] A similar survey covering several decades of research worldwide found a range of 5 percent to 15 percent in conservation effect from direct, real-time usage feedback.[44] Although these are significant decreases in usage, adoption of real-time energy usage displays is likely to be limited for some time.[45] As a result, and using adoption rates of 2 percent to 5 percent for the Reference Case and Ideal Case, respectively, we find the economic benefits from customer energy management to range from $0.77 to $1.92 per customer per year. As with many other participation-dependent Smart Grid capabilities, these economic benefits are typically much higher for customers using real-time data, and minimal or nonexistent for customers not using them.

Environmental Benefits of Customer Energy Management

Environmental benefits accrue directly from the conservation effect of customer energy management. We calculate 14 to 34 pounds per customer per year in carbon dioxide equivalent emissions reduction.[46]

Drivers of Customer Energy Management Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Customer Energy Management		X		X

The number of customers using real-time usage data is a critical driver of energy management benefits. Research indicates that coupling this information with incentives such as those offered in time-varying rate or prepayment programs can drive greater benefits than either incentives or feedback on their own.[47] Figure 4 summarizes the results of multiple studies, which collectively indicate a greater impact when an incentive program is paired with an enabling technology, such as a real-time energy usage display device.

43 Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "The Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence" (meta-analysis), *Energy* 35, 2010, 1.

44 Sarah Darby, "The Effectiveness of Feedback on Energy Consumption" (literature review), University of Oxford Environmental Change Institute, April 2006, 3.

45 Janelle LaMarche, et al, "Home Energy Management: Products and Trends" (white paper), Fraunhofer Center for Sustainable Energy Systems, 1.

46 Please see calculations in the appendices.

47 Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "The Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence" (meta-analysis), *Energy* 35, 2010, 5.

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to Commission Staff's First Request for Information
Dated April 2, 2018

Case No. 2018-00005

Question No. 10

Witness: John P. Malloy

Q-10. Refer to Malloy Testimony, page 10.

a. State whether the electric AMS meters will have a second radio that allows for direct communication to the customer of real-time data (e.g., 8 second).

b. If so, state whether the Companies will make this data available to customers.

c. If the Companies were to make real-time data available to their customers, explain what the estimated costs would be to the Companies, and to their customers.

A-10.

a. The electric AMS meters feature Zigbee communication capability to interact with Home Area Network (HAN) devices. This capability could be used to support future initiatives or independently interact with other customer-procured equipment for nearly real-time monitoring. This functionality is enabled by AMS and typically displayed through in-home devices. Zigbee is a wireless language enabling communication between certain low-power, digital radio devices. See http://www.zigbee.org/what-is-zigbee/.

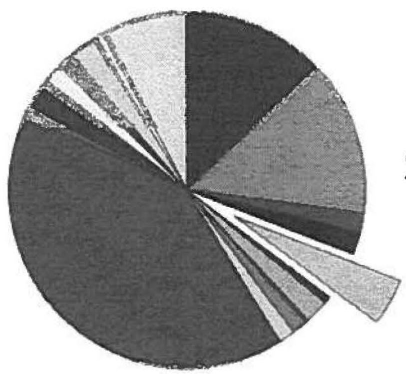
b. The Companies continue to evaluate the market for in-home devices, but do not currently have any plans to provide for real-time data monitoring. The Companies are considering providing support for customers who procure their own equipment to make use of the available Zigbee communications.

c. The Companies do not currently have plans to offer in-home devices, and have not completed any financial evaluations regarding such an offering. Informal discussions with other utilities who have offered in-home devices as part of their deployments indicate that the devices are expensive (as much as $150 per device), have limited usefulness to the customer, and have thus proven not to be cost-effective.

ATTORNEY GENERAL
EXHIBIT 10

Meter Operations Capital (Benefit 6)

$ NPV in millions/% of total benefits



$16.58
4.3%

Savings Category – Deferred Capital

Background on Benefit

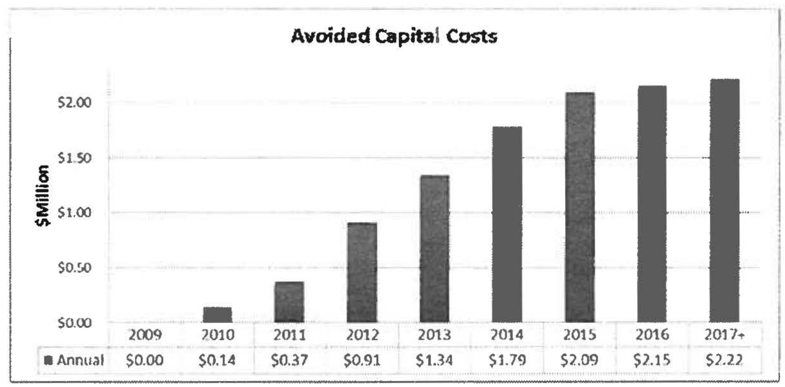
- With the deployment of AMI technology, capital costs associated with the replacement of traditional meters and related equipment will be significantly reduced.
- Without AMI deployment, traditional meters, and other related equipment, such as handheld devices, would have to be replaced over time resulting in regular capital costs. As penetration of smart meters increases, the need to replace traditional meters and other manual meter reading equipment will decrease significantly.
- Smart meters do not require the use of equipment related to manual meter reads such as handheld devices, resulting in reduced costs.
- It must be noted that smart meters will also need to be replaced after life cycle completion, estimated to be 20 years.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- The meter and equipment purchase and installation labor budgets for Duke Energy Ohio
- Labor and material inflation rates

Modeled Economic Benefits



LG&E/KU
EXHIBIT 1

Lessons Learned will Optimize Future Investments and Maximize PSCO Customer Value

The SmartGridCity™ demonstration project stands in stark contrast to smart grid deployments prompted by investment grants from the U.S. Government's American Recovery and Reinvestment Act (ARRA) smart grid program. Smart Grid Investment Grant awards stipulated that the grants and matching funds had to be spent quickly to stimulate the economy. Accordingly, smart grid deployments were driven by the ARRA grants' prioritization of investment over learning. The SmartGridCity™ demonstration project, however, prioritized learning over investment. A review of publicly available smart grid business cases indicates that IOUs completing full deployments are investing from $500 to $700 per electric customer (outliers discounted). By contrast, PSCO elected to spend approximately $33 per electric customer to help ensure that any large investments it chooses to make in its grid will be as cost-effective as possible.

More to the point, and as described below, the actionable lessons learned in SmartGridCity™ provide real value to PSCO customers by optimizing future grid investments. Informed by the lessons from SmartGridCity™, PSCO is prepared to develop business cases with confidence and knowledge to share with stakeholders as part of a structured and informed grid strategy development and investment decision process.

Lessons from the project that help optimize smart grid investments are illustrated throughout this document, but some of the more valuable technology- and capability-specific lessons are described below. For more information on such lessons, please see the 'Value Creation by Smart Grid System' section below or even more detailed descriptions in the Appendix 1 – Value Proposition Evaluation.

Distributed Energy Resource Control (DERC)/Demand Response (DR)

'Distributed Energy Resource Control' as implemented in SmartGridCity™ consists primarily of advanced capabilities to control customer loads through home area networks, or HANs. PSCO has plans in place to complete 1,264 HAN installations from October 2011 to May 2012 in the residences of customers participating in the time-differentiated pricing pilot. Top lessons learned about HANs include:

- HANs offer significant features beyond those available from traditional Demand Response technologies, but the impact of these features on effectiveness is not yet known and is currently under study.
- For the foreseeable future, an impractical number of pre-requisites exist for HAN technology to be effectively used to increase the utilization of renewable generation.
- HAN technology is extremely expensive and evolving rapidly, presenting high capital and technological obsolescence risk; it can also present additional utility system security risks if not carefully managed.

Advanced Metering Infrastructure (AMI)

Advanced meters offer many types of upgrades over traditional meters, facilitating time-differentiated rates, communicating with the utility in real-time, automating meter reading, sensing grid conditions, and other optional features. The options, benefits, and roles are specific to each utility and driven by existing operations, customer priorities, distribution grid strategy, rate designs, cost structures, and other factors. AMI investment choices are therefore highly complex and lessons learned are therefore very important to investment decisions. Further, since the service life of this equipment is typically 20 years or more, short term decisions have long term implications. Advanced meters have been installed in about half of the customer premises in SmartGridCity™. Top lessons learned about AMI include:

- Advanced meters offer extremely long customer payback periods if meter reading has already been automated (as it has in PSCO) and/or time-differentiated rates are adopted slowly by customers.
- Advanced meters offer capabilities likely to improve the satisfaction of some customers through the increase in ability to control energy usage and better Call Center responsiveness.
- Advanced meter and relevant communication technologies are still evolving rapidly and associated costs are dropping.
- Advanced meters can also serve as sensing

LG&E/KU
EXHIBIT 2

*Honorable Allyson K Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Honorable Kurt J Boehm
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Rick E Lovekamp
Manager - Regulatory Affairs
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Honorable Iris G Skidmore
415 W. Main Street
Suite 2
Frankfort, KENTUCKY 40601

*Honorable Kendrick R Riggs
Attorney at Law
Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
Louisville, KENTUCKY 40202-2828

*Robert Conroy
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Duncan W Crosby
Stoll, Keenon, Ogden PLLC
2000 PNC Plaza, 500 West Jefferson St
, 40202-2828

*Kent Chandler
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Kentucky Utilities Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Eileen Ordover
Legal Aid Society
416 West Muhammad Ali Boulevard
Suite 300
Louisville, KENTUCKY 40202

*Larry Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Thomas J FitzGerald
Counsel & Director
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KENTUCKY 40602

*Honorable Lisa Kilkelly
Attorney at Law
Legal Aid Society
416 West Muhammad Ali Boulevard
Suite 300
Louisville, KENTUCKY 40202

*Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Justin M. McNeil
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Rebecca W Goodman
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204