Exhibit No.:	
Issues:	Fuel Adjustment Clause DSM Cost Recovery Mechanism and Residential Lighting and Appliance Program
Witness:	John A. Rogers
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Rebuttal Testimony
Case No.:	ER-2010-0036
Date Testimony Prepared:	February 11, 2010

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

REBUTTAL TESTIMONY

OF

JOHN A. ROGERS

UNION ELECTRIC COMPANY
d/b/a
AMERENUE

CASE NO. ER-2010-0036

Jefferson City, Missouri
February

****<u>Denotes Highly Confidential Information</u>****

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service.	)))	Case No. ER-2010-0036

AFFIDAVIT OF JOHN A. ROGERS

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

John A. Rogers, of lawful age, on his oath states: that he has participated in the preparation of the following Rebuttal Testimony in question and answer form, consisting of 20 pages of Rebuttal Testimony to be presented in the above case, that the answers in the following Rebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

John A Rogers
John A. Rogers

Subscribed and sworn to before me this 11th day of February, 2010.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer
Notary Public

Table of Contents

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CASE NO. ER-2010-0036

Q. Please state your name and business address.

A. My name is John A. Rogers, and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. What is your present position at the Missouri Public Service Commission?

A. I am a Utility Regulatory Manager in the Energy Department of the Utility Operations Division.

Q. Are you the same John A. Rogers that contributed to Staff's Revenue Requirement Cost of Service Report (Staff Report) filed on December 18, 2009 and to Staff's Class Cost of Service Rate Design Report (Staff CCOS Report) filed on January 6, 2010?

A. Yes, I am.

Q. Would you please summarize the purpose of your rebuttal testimony?

A. I address certain direct testimony of AmerenUE and intervenor witnesses relating to the AmerenUE proposed fuel adjustment clause and the demand-side management (DSM) subject areas. I update the Commission regarding AmerenUE's recent and planned donations of compact florescent light (CFL) bulbs to food banks and to city governments and present Staff's concerns regarding AmerenUE's plans to include these donations and related costs in its Residential Lighting and Appliance (L&A) program. The fact that Staff does not specifically take issue with a statement of an AmerenUE, Office of Public Counsel, or intervenor witness should not be construed as an indication of agreement or acceptance by Staff. My recommendations to the Commission are as follows:

1) Commission should rely upon Staff's fuel run in determining the seasonal Net Base Fuel Cost (NBFC) rates to be included in Union Electric Company d/b/a AmerenUE's (AmerenUE's) Fuel Adjustment Clause (FAC) tariff sheets;

2) Commission should generally continue the current regulatory asset treatment of AmerenUE's DSM costs until the Commission has established policies and rules to implement the Missouri Energy Efficiency Investment Act ("MEEIA" or Section 393.1075 2009 RSMo Cum. Supp.); and

3) Commission should order that the AmerenUE L&A energy efficiency program expenses remain in the regulatory asset account.

<u>Fuel Adjustment Clause</u>

Q. Have you reviewed the Fuel Adjustment Clause that AmerenUE proposes in this case, including the changes it proposes to its existing FAC tariff sheets?

A. Yes. I reviewed AmerenUE's proposed FAC tariff sheets presented in the testimony of AmerenUE witness Lynn M. Barnes.

Q. Did your review cause you any concerns?

A. Yes. I have concerns with the seasonal Net Base Fuel Cost (NBFC) rates AmerenUE proposes.

Q. What are those concerns?

A. AmerenUE has relied on a different fuel run for determining the seasonal NBFC rates for its proposed FAC than it used for determining it revenue requirement and its seasonal net base fuel cost rates are counterintuitive.

Q. Would you explain what you mean by stating AmerenUE's proposed seasonal NBFC rates are counterintuitive?

A. The Summer NBFC rate is lower than the Winter NBFC rate, and this has never been the case for AmerenUE or any other electric utility in Missouri. In fact, AmerenUE's proposed Summer NBFC rate is significantly lower than its proposed Winter NBFC rate.

Q. Please specify the FAC seasonal NBFC rates proposed by AmerenUE and FAC seasonal NBFC rates proposed by Staff.

A. Schedule LMB-E3-5 attached to the direct testimony of AmerenUE witness Lynn M. Barnes contains the following language in the definition of NBFC in the AmerenUE proposed FAC tariff sheets:

> The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is 1.102 cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is 1.494 cents per kWh.

Schedule JAR-1 of the Staff CCOS Report contains the following language in the definition of NBFC on Sheet No. 98.11 of the Staff proposed FAC:

> The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is 1.449 cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is 1.275 cents per kWh.

Q. Please compare the various proposed NBFC rates in your last answer to the NBFC rates the Commission approved in AmerenUE last general rate case, Case No. ER-2008-0318.

A. The Summer NBFC Rate approved in Case No. ER-2008-0318 is 1.001 cents per kWh and the Winter NBFC Rate approved in Case No. ER-2008-0318 is 0.690 cents per kWh. The following table summarizes the NBFC rates proposed by AmerenUE, the proposed NBFC rates in the Staff CCOS Report, and the current NBFC rates:

NBFC Rate Comparison				
	Summer		Winter	
	¢/kWh	Δ% Current	¢/kWh	Δ% Current
AUE Proposed	1.102	10%	1.494	117%
Staff Proposed	1.449	45%	1.275	85%
Current Tariff	1.001	0%	0.690	0%

Q. Has Staff performed an investigation to determine the causes of the significant differences between AmerenUE's proposed NBFC rates and the proposed NBFC rates in the Staff CCOS Report?

A. Yes.

Q. Would you please describe Staff's investigation and findings?

A. Yes. Staff's investigation determined that the fuel run AmerenUE used to estimate NBFC for its proposed FAC is not the same fuel run AmerenUE used to determine the revenue requirement it sponsors in this case. Further, Staff's investigation determined that AmerenUE's FAC fuel run estimates of monthly off-system sales revenues and volumes are significantly different from those of Staff. Specifically, Summer (June through September) off-system sales revenue in AmerenUE's FAC fuel run is $60 million greater than the Summer off-system sales revenue in the Staff's fuel run and Winter (October through May) off-system sales revenue in AmerenUE's FAC fuel run is $60 million less than the Winter off-system sales revenue in the Staff fuel run.

Staff also created a chart that compares the off-system monthly kWh sales for Staff's fuel run, for AmerenUE's FAC fuel run, and for the fuel run AmerenUE used for its proposed revenue requirement, each of which were filed in this case. This chart is included below and illustrates that the off-system monthly kWh sales (OSS) in AmerenUE's FAC fuel run are distinctly different from the OSS in AmerenUE's revenue requirement and from the OSS in Staff's fuel run.

** **

Q. What do you conclude and recommend concerning the NBFC rates for this case?

A I conclude that AmerenUE's FAC fuel run is not an appropriate fuel run to use to determine the FAC seasonal NBFC rates in this case. Staff's fuel run has been revised since the Staff CCOS Report was filed and will again be revised during true-up. Therefore, I recommend the Commission rely upon Staff's fuel run.

Demand-Side Management **Programs** Cost Recovery Mechanism

Q. What DSM cost recovery mechanism does AmerenUE propose in this case?

A. AmerenUE witness Stephen Kidwell proposes at page 17 of his direct testimony a DSM cost tracker which would place the full amount of the regulatory asset as of the true-up date in base rates plus the average of incremental DSM budgeted amounts for 2010 and 2011. The tracker would accumulate the difference between the amount in rates and the actual amount spent on DSM programs. At the Company's next rate case, AmerenUE would recover (or refund) any amounts in the tracker through a three-year amortization of the balance, with interest.

Q. Does the DSM cost tracker proposed by AmerenUE include recovery of lost revenue and/or shareholder incentives?

A. No, it does not. However, Mr. Kidwell in his direct testimony, page 17, lines 1-4, states that the mechanism that would best allow for cost recovery would include an annual incentive provision based on a percentage of the difference between AmerenUE's avoided costs and the costs associated with implementation of demand side measures. Mr. Kidwell did not propose an incentive mechanism in his testimony stating that AmerenUE needed additional experience and dialogue with stakeholders. AmerenUE did organize a number of meetings with parties to the case which were treated as settlement sessions to discuss and evaluate alternative methods related to DSM cost recovery, recovery of lost revenue and shareholder incentives. Although this stakeholder process did not result in a DSM cost recovery mechanism that the parties could agree to, the process was productive and represents the first cooperative learning experience in Missouri concerning a comprehensive understanding of the impact of DSM programs on customers and shareholders of Missouri's investor-owned electric utilities.

The Staff is appreciative of the effort made by AmerenUE, but is concerned that the fact that AmerenUE and the parties have not been able to fashion a resolution of these matters may be characterized by some as indication of certain participants not being cooperative or being overly technical in their approach to areas for which there are now federal and state direction. Many of the parties, including Staff, dedicated a considerable amount of time and effort to these discussions. Staff believes that the time and resource constraints, along with the characterization of these discussions as settlement talks, greatly impacted the ability of the parties to reach an agreement on a DSM cost recovery mechanism for AmerenUE.

Q. What have been AmerenUE's actual expenditure levels for its DSM programs compared to budget?

A. AmerenUE reports that it spent \$9.9 million[1] on its DSM programs in the first program year (October 1, 2008 through September 30, 2009) as compared to \$25.0 million planned for the first program year in its preferred resource plan filed in its recent Chapter 22 Electric Utility Resource Planning compliance filing in Case No. EO-2007-0409. During the first three months of the second program year, AmerenUE spent \$3.8 million on its DSM programs compared to \$32.1 million for the second program year (12 full months) in its preferred resource plan.

Q. What do you conclude from your last answer?

A. AmerenUE is still in the process of "ramping up" its DSM programs and is greatly under-spending its planned budget for DSM. Until AmerenUE can demonstrate that it has ramped up its DSM programs and has a sustained expense amount, the proposed DSM

[1] AmerenUE Demand-Side Resources Performance Summary Report for February 4, 2010 provided by AmerenUE at February 4, 2010 AmerenUE DSM stakeholder quarterly update meeting. Such AmerenUE DSM stakeholder quarterly update meetings are required as a result of the Partial Stipulation and Agreement in Case No. EO-2007-0409.

cost tracker will likely result in a large over collection of revenue. As a consequence, Staff does not support the DSM tracker proposed by Mr. Kidwell. I say this in light of my statements at page 46, lines 34-35, page 47, lines 14-16, and page 45, lines 30-33 of my section of the Staff Report that there is just not enough information in Mr. Kidwell's direct testimony, many details of AmerenUE's proposal need to be clarified or determined, and AmerenUE should continue the current regulatory asset treatment of demand-side costs until the Commission has established policies and rules to implement Senate Bill 376, the Missouri Energy Efficiency Investment Act.

Q. Other than AmerenUE and Staff, what other parties to this case discuss or propose DSM cost recovery mechanisms?

A. Missouri Department of Natural Resources (MDNR), National Resource Defense Council (NRDC), Missouri Industrial Energy Consumers (MIEC), and Missouri Energy Group (MEG) filed direct testimony concerning DSM cost recovery mechanisms.

Q. Please summarize the positions of MDNR, NRDC, MIEC and MEG with respect to DSM cost recovery.

A. These parties have expressed a broad range of positions which I have highlighted in Schedule JAR-1.

Q. What is Staff's reaction to the broad range of positions taken by the parties in this case?

A. AmerenUE, Staff, MDNR, NRDC, MIEC and MEG have very diverse positions at this time. Since these positions were filed by the parties following the settlement sessions on DSM cost recovery mechanisms, this diversity of positions suggests to Staff that the Commissioners should not think that a settlement is imminent or even remotely possible in the near term. Because the direct testimony of NRDC witness Pamela Lesh is the most comprehensive with regards to different aspects of DSM cost recovery, and in consideration of Staff's time and resource limitations, I have chosen to respond to the NRDC direct testimony.

Q. Please summarize the direct testimony of NRDC.

A. In her direct testimony, NRDC witness Pamela Lesh has five recommendations that she makes to the Commission. I will discuss each of these recommendations and provide Staff's comments relative to each recommendation later in my rebuttal testimony. NRDC's recommendations are characterized by Ms. Lesh at page 6, lines 13-15 of her direct testimony, as "the five policy 'legs' that we [NRDC] have found best support a utility in meeting its stated goal of helping its customers achieve all cost-effective energy efficiency through the most effective means." She further states at page 6, lines 19-21, that the context of NRDC's recommendations is based on "the advent of a decade – 2010 to 2020 – in which America's electric utilities must focus, first and foremost, on helping their customers increase their energy efficiency."

Q. Does Staff agree that AmerenUE has a stated goal of helping its customers achieve all cost-effective energy efficiency through the most effective means?

A. No. On its website, AmerenUE states "We may not know what the future holds, or exactly what the energy business will look like tomorrow. But we're working to ensure that secure, reliable, sustainable energy will be its foundation. That is our promise to you."[2] On that same web page AmerenUE includes promoting energy efficiency programs that save customers money, conserve generating capacity and lessen the urgency to build new

[2] http://www.ameren.com/Features/Pages/FuturePlanning.aspx.

plants as one of the ways it is "working hard to provide for our customers today while propelling them – and our company -- forward."

Q. Does Staff believe that helping its customers achieve all cost-effective energy efficiency through the most effective means should be a goal of AmerenUE?

A. The Missouri Energy Efficiency Investment Act (MEEIA) (Section 393.1075.4 2009 RSMo Cum. Supp.) states that "[t]he commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings." There are a number of other subsections to Section 393.1075. Staff has not received any direction that achieving all cost-effective energy efficiency as defined by NRDC's reading of MEEIA or any federal legislation is a mandated goal of AmerenUE.

Q. Then are the five policy "legs" described by Ms. Lesh irrelevant?

A. No, they are relevant. However, since the context or what is required of AmerenUE and the Commission is different than what NRDC indicates, the importance of the five recommendations of NRDC must be re-examined.

Q. What is the first recommendation of Ms. Lesh?

A. AmerenUE should adopt goals for the annual reduction of energy of 1.5% by around 2012 and 2% by 2015.

Q. Do you agree that goals should be set?

A. Goals are important. MEEIA states a goal of achieving all cost-effective demand-side savings. AmerenUE is just completing its demand-side potential study. One of the objectives of the study is to assess and understand the demand-side potential for its service territory. If this study shows that the achievable potential is a 3% annual reduction in energy but the Commission has set the goal at 1.5%, Staff is concerned that AmerenUE may just stop at 1.5%. On the other hand, if the study shows that the achievable potential is a 1% annual reduction in energy and AmerenUE is required to meet a 1.5% reduction, then AmerenUE would be required to meet a goal that is not cost-effective. The parties and AmerenUE need time to evaluate the results of AmerenUE's demand-side potential study to determine what "all cost-effective demand-side savings" (i.e., energy efficiency and demand-side programs) means for AmerenUE.

Q. What is the second recommendation of Ms. Lesh?

A. Ms. Lesh supports the DSM cost tracker proposed by AmerenUE witness Stephen Kidwell.

Q. Does Staff agree with this recommendation?

A. For reasons previously discussed in this rebuttal testimony, Staff cannot agree with the use of the DSM cost tracker proposed by Mr. Kidwell. Ms. Lesh criticizes the current regulatory asset account recovery mechanism, because it does not include the return afforded supply-side resources. Staff agrees that the amortized amount should receive a return and suggested this correction to the regulatory asset account for DSM costs as presented by Stephen M. Rackers in the Staff Report.

Q. What is the third recommendation of Ms. Lesh?

A. Ms. Lesh proposes a Revenue Decoupling Mechanism (RDM).

Q. What is a RDM?

A. On page 2 of her paper "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling" which is Attachment 1 to her direct testimony, Ms. Lesh states that "[d]ecoupling is a regulatory term indicating that, through any one of several means, a given energy utility does not derive the portion of its revenues necessary to provide it an opportunity to recover its fixed costs of service on the basis of its sales of natural gas or electricity." And further states that "[o]ne primary means of decoupling, albeit with many variations, is through a regulatory adjustment mechanism that adjusts rates periodically to ensure that a utility records as revenue for fixed cost recovery no more and no less than the amount of revenue authorized for that cost coverage." (Lesh, Direct Testimony, Attachment 1, p. 2).

Q. Isn't that what the straight fixed/variable rate design adopted by this Commission for natural gas utilities is designed to do?

A. Yes. However, decoupling goes further than the straight fixed/variable rate design. As Ms. Lesh further explains on page 2 of her Attachment 1:

> . . . On some regular basis, the decoupling mechanism provides a rate adjustment to ensure that customers, in effect, receive refunds or pay surcharges based on whether the revenues the utility actually receives from customers were less or greater than the revenues the regulator authorized. . . .

So in effect, the Commission sets the amount that the utility will receive from its customers to cover its fixed costs. If revenues collected from the customers are less than this amount, then the utility will be permitted to recover the additional amount in rates. If revenues collected from the customers are more than the fixed costs intended to be recovered, the utility refunds the excess revenues.

Ms. Lesh states at page 25, lines 1-5 of her direct testimony that parties to proceedings in which RDM is being considered usually raises three concerns regarding RDM:

- That the RDM will cause the utility to lose focus on the need to control costs

- That the RDM will eliminate or reduce the benefit of regulatory lag

- That the RDM will shift risk to customers

On pages 25 through 28 of her direct testimony, Ms. Lesh discusses these concerns but concludes that the risk to customers of not implementing RDM is greater than the risk of implementing it. However, this is not the risk of safe and reliable service at a reasonable rate. It is the risk of :

> … never experiencing what could happen if Missouri aligned the interests of AmerenUE and its customers toward increasing the efficiency with which those customers use electricity to do work outweighs the risk that customers could temporarily experience lower rates because regulatory policy leaves consumption as the driver of at least a part of the utility's recovery of fixed costs and (a) intentionally refuses to recognize the effect of planned energy efficiency in setting rates; or (b) assumes that, over time, regulatory lag will "benefit" customers through temporarily lower rates more often that it harms them through temporarily higher rates. [Lesh, p. 30, ls. 11-18].

Q. What is Staff's position regarding RDM?

A. Staff takes the position that a significant policy change such as RDM should be very carefully examined in an electric industry-wide setting that is not time constrained. Also, Section 393.1075.5 of MEEIA includes a requirement that "[p]rior to approving a rate design modification associated with demand-side cost recovery, the commission shall conclude a docket studying the effects thereof and promulgate an appropriate rule." While Staff expects that different parties have different interpretations of this provision, it is Staff's position that the Commission should conclude a docket studying the effects of RDM before it adopts it for any of its Missouri jurisdictional electric utilities.

Staff is very cautious about changing the regulatory structure that has apparently served Missouri retail ratepayers well, as far as ratemaking is concerned.

Granted, the current regulatory structure hasn't resulted in Missouri Commission jurisdictional electric utilities implementing large energy efficiency programs. But on advice of counsel, Staff doesn't believe that there presently is any federal or state <u>mandate</u> for Missouri Commission jurisdictional electric utilities to achieve all cost-effective demand-side savings.

Q. What is the fourth recommendation of Ms. Lesh?

A. Ms. Lesh recommends, beginning at page 31, line 11 of her direct testimony, that the Commission endorse the concept of a performance-based incentive as a necessary measure to propel Missouri's energy efficiency savings to much higher levels and that the parties to this case participate in a collaborative process to develop such an incentive.

Q. What is the fifth recommendation of Ms. Lesh?

A. Beginning at page 35, line 15 of her direct testimony, Ms. Lesh recommends that the Commission should require that AmerenUE establish an independently-run evaluation and verification program.

Q. What is Staff's position with respect to NRDC's recommendations concerning (a) performance based incentives and (b) independently-run evaluation and verification of DSM program results?

A. Performance based incentives can be an important part of a DSM regulatory framework, but must be considered in the context of all of the provisions of the framework. DSM cost recovery, fixed cost recovery and shareholder incentives should seek and result in maximum overall benefits. The balance that is sought and achieved is all important. Staff believes that independently-run evaluation and verification should be a required feature of

DSM cost recovery mechanisms, especially when a shareholder incentive is a part of the mechanism.

Q. As previously noted, Ms. Lesh attached a paper to her testimony as Attachment 1 that summarizes her research into DSM cost recovery. Are you aware of anything at this time that should be added?

A. Yes. Ms. Lesh may be including in her rebuttal testimony, but I am attaching as Schedule JAR-2 The Edison Foundation Institute for Electric Efficiency's January 2010 report titled ***State Energy Efficiency Regulatory Frameworks***. This document highlights the approach taken in each state and the District of Columbia with respect to DSM cost recovery, lost revenue recovery, and shareholder incentives. I am supplying this document without providing any support as to its accuracy. I am merely providing this information to the Commission. I have made no attempt to verify any of the information in the report or determine whether it reflects important nuances that may exist in the individual states.

Q. What do you observe from your review of Schedule JAR-2?

A. I can make several generalizations using information from this report.

1) Direct recovery cost of DSM costs is being addressed in three general ways (rate case, system benefit charge or tariff rider/surcharge) and that the states are fairly well divided on the preferred approach;

2) Fixed cost recovery is being addressed in two general ways (decoupling and lost revenue adjustment mechanism) and that at the moment states seem to be moving to decoupling with eleven states having approved decoupling, eight states with pending decoupling cases, seven states having approved lost

revenue adjustment mechanisms and one state with a pending case concerning lost revenue adjustment mechanism;

3) Shareholder performance incentives are a part of the energy efficiency regulatory framework in twenty states and are pending in six states;

4) For those states with shareholder performance incentives, there is a wide range of approaches;

5) Only two of the eight states bordering Missouri have a mechanism for recovery of fixed costs (Oklahoma and Kentucky have lost revenue adjustment mechanisms) and none have approved or have pending review of decoupling mechanisms; and

6) Only two of the eight states bordering Missouri have approved shareholder performance incentives (Oklahoma and Kentucky) and one has a pending case for shareholder incentives (Kansas).

Q. What is Staff's recommendation concerning AmerenUE's request for a DSM cost tracker?

A. As stated in the Staff Report, Staff proposes that AmerenUE generally continue the current regulatory asset treatment of DSM costs until the Commission has established policies and rules to implement the Missouri Energy Investment Act (MEEIA), Section 393.1075, 2009 RSMo Cum. Supp. Staff does propose one change to the current treatment. In the Staff Report in the instant case, Stephen M. Rackers states:

> In this case the Staff has included in its development of AmerenUE's revenue requirement presented here, one tenth of the actual amount spent by the Company as the annual amortization expense associated with DSM programs. In addition, the Staff has included the actual amount spent by the Company on DSM programs in AmerenUE's rate base.

In rate base, the unamortized balance is allowed to earn a return at AmerenUE's authorized overall rate of return. In Case No. ER-2008-0318, one-tenth of the balance in the regulatory asset account for DSM programs that existed as of the true-up cut-off date in that case, September 30, 2008, was included in expense. The balance of the account, $876,070 was not included in AmerenUE's rate base. The Company was allowed to accrue interest at its AFUDC rate on the unamortized balance of DSM program costs in the regulatory asset account.

Q. Why is Staff making this specific recommendation?

A. The Commission has directed Staff to initiate a series of workshops to implement MEEIA and the Energy Independence And Security Act of 2007 ("EISA"), including new PURPA Section 111(d)(17) Rate Design Modifications to Promote Energy Efficiency Investments Standard. The workshops are scheduled to begin on February 22, 2010. Commission rules for MEEIA and the resulting Missouri DSM regulatory framework is very important for Missouri's customers of electric investor-owned and the shareholders of Missouri's investor-owned electric utilities and will require careful consideration by all stakeholders. Staff believes it would be premature for the Commission to move away from its current DSM regulatory asset account approach to DSM cost recovery until it has engaged in the process that it has even set for itself to comply with MEEIA and EISA.

Residential Lighting and Appliance Program

Q. Have there been relevant developments respecting AmerenUE's Residential Lighting and Appliance Program (L&A Program) that should be addressed by the Commission, since the Staff Report was filed on December 18, 2009?

A. Yes. AmerenUE recently publicly announced that it is donating CFL bulbs to various food bank organizations, AmerenUE advised Staff and others at a recent meeting of its plans for further CFL bulbs donation, and there has been a very recent article in the St. Louis Post-Dispatch mentioning one of these AmerenUE CFL bulb donations.

Q. Please describe your knowledge of such donations.

A. On January 26, 2010 AmerenUE announced through a Media Release that it is partnering with Operation Food Search (OFS) to give away 40,000 CFL bulbs to income-qualified St. Louis Metro area families to help them save energy in their homes and money on their electric bills. Schedule JAR-3 is a copy of the Media Release announcing the AmerenUE partnership with OFS. Further, on February 4, 2010 AmerenUE informed Staff, the Office of Public Council (OPC) and other participants in its demand-side management programs (DSM) stakeholder quarterly update meeting in St. Louis, that AmerenUE is expanding the L&A program to include "social marketing distribution opportunities" including food banks and American Recovery and Reinvestment Act of 2009 (ARRA) programs. At this meeting AmerenUE stated that it planned to donate CFL bulbs to the City of St. Peters in response to the city's request to purchase discounted CFL bulbs from AmerenUE. A St. Louis Post-Dispatch article on February 10, 2010 (see Schedule JAR-4) states that "AmerenUE gave the city an additional 40,000 bulbs," as part of the City of St. Peters' plan to use a $512,000 stimulus grant from the Department of Energy to pay for light bulbs, a station that will allow residents to switch the air in their tires for hydrogen, energy efficiency improvements in city buildings and free thermostats for some residents.

Q. How does AmerenUE plan to account for the costs related to the donation of CFL bulbs to OFS and to the City of St. Peters?

A. At the February 4, 2010 AmerenUE DSM stakeholder quarterly update meeting, AmerenUE stated and presented in a PowerPoint presentation that costs related to the donation of CFL bulbs to OFS and to the City of St. Peters would be included as costs of the L&A program.

Q. Do you agree that donation of CFL bulbs to charitable organization or to city governments should be a part of the L&A program?

A. No.

Q Why not?

A. AmerenUE tariff Sheet No. 239 states the purpose of the L&A program as:

> The Lighting and Appliance Program is intended to reduce energy use in residential lighting and appliance products by encouraging selection of ENERGY STAR qualified products through Market Transformation efforts.

AmerenUE tariff Sheet No. 237 defines market transformation as:

> A strategy that promotes the manufacture and purchase of energy-efficient products and services. The goal of this strategy is to induce lasting structural and behavioral changes in the marketplace, resulting in increased adoption of energy-efficient technologies.

AmerenUE tariff Sheet Nos. 239 – 241 define ten Program Provisions for the L&A program including: special promotions, market share incentives, buy-down/mark-down, point of purchase display materials, ENERGY STAR qualified products labeling, product lists, sales tools for program partners, listings on the UEfficiency.com website, retailer training and refresher training, and direct/indirect customer incentives.

Staff notes that donation of CFL bulbs (or ENERGY STAR appliances) is not included in the Program Provisions of the L&A program. Further, Staff does not believe that the donation of CFL bulbs should be made a part of the L&A program. The donation of CFL bulbs is inconsistent with the concept of partnering with manufactures and retailers in an effort to transform the market for ENERGY STAR products. The donation of CFL bulbs will reduce the opportunity program partners will have to sell CFL bulbs through participation in the L&A Program.

Q. Does Staff believe the L&A Program costs should be included in this case?

A. No. In its Staff Report, Staff expressed its concern for the prudence and performance of the L&A program and recommended that the L&A program expenses remain in the regulatory asset account. AmerenUE's intention to expand the L&A Program Provisions to include donations of CFL bulbs further increases the level of concern that Staff has for the L&A program.

Q. Does that conclude your rebuttal testimony?

A. Yes.

Item No.	Filing	Filed On Behalf Of	Position
14	Direct Testimony of Stephen M. Kidwell	AmerenUE	• Currently, costs for administration, research, design, development, implementation and evaluation are booked to a regulatory asset and amortized over 10 years, including interest at the Company's AFUDC rate (p. 12, lines 16-18). • The current method for AmerenUE to recover its demand side program costs does not create a level playing field between supply-side and demand-side investments, as required by SB 376 (2009). The current regulatory asset established in Case No. ER-2007-0002 is not sufficient to provide timely recovery of expenditures (p. 2, lines 15-21). In addition, Ameren believes there is no basis for the 10-year amortization period (p. 14, lines 27). • After considering the needs for more timely cost recovery and the policy implications of SB 376 (2009), AmerenUE's preference is to not continue the current capitalization and amortization framework (p. 16, lines 16-18). • There may be options to make the capitalization/amortization accounting approach more viable such as an approach similar to Nevada. Nevada uses the capitalization/amortization accounting approach, but is vastly different than the existing Missouri approach as it has cost recovery and incentive components (p. 18, line 20- p. 19, line 21). • AmerenUE proposes a potential solution for improving the current cost recovery mechanism, but hopes to discuss many potential mechanisms with other interested parties (p.3, lines 16-18). • AmerenUE proposes a DSM tracker for DSM cost recovery. Under this tracker, the full amount of the regulatory asset as of February 28, 2010 would be included in base rates, plus the average of incremental budgeted amounts for 2010 and 2011. The tracker would accumulate the difference between the amount in rates and the actual amount spent on DSM programs. At the Company's next rate case, AmerenUE would recover (or refund) any amounts in the tracker through a three year amortization of the balance, with interest (p. 17, lines 5-12). • AmerenUE needs additional dialogue with stakeholders before they can adopt a definitive position on how incentive and lost revenue mechanisms would be addressed in the proposed tracker (p. 17, lines 15-18). • There are several other tools the Commission might use to level the playing field between demand-side and supply-side investments, including the capitalization of investments in demand-side programs, rate design modifications, sharing of the savings to allow the utility to retain a portion of the net benefits of a program,

			increasing the utility's ROE on its energy efficiency investments, revenue decoupling, shortening the amortization period over which demand-side costs are recovered and adoption of a lost revenue recovery mechanism. These all are worth further discussion with parties in the case (p. 18, lines 12-19).

221	Direct Testimony of Pamela Lesh	Natural Resources Defense Council	• The Commission should require that AmerenUE increase its 2009-2011 energy efficiency goals. AmerenUE plans to help its customers save about 800,000 MWh over the three years ending in 2011. AmerenUE's goals are significantly lower than even the lowest end of the spectrum in the Midwest. AmerenUE should adopt goals that reach 1.5% by around 2012 and 2% by 2015, which are in line with the other Midwest states (p. 9, line 7- p. 11, line 14).
			• The Commission should approve a cost tracker mechanism for AmerenUE to recover its energy efficiency expenditures. Agrees with AmerenUE that its current method of recovering energy efficiency costs is inadequate and compares unfavorably to best practices across the country (p. 11, line 15-p.14, line 13).
			• The Commission should approve a revenue decoupling mechanism (RDM) for AmerenUE. A RDM is the only regulatory policy that eliminates a utility's incentive to increase sales of electricity, as well as ensure that the savings it helps its customers achieve do not come at the cost of its bottom line. As of November 2009, ten states have adopted electric decoupling, with nine more considering the matter.
			  o A performance-based incentive for energy efficiency savings does not substitute for decoupling. A performance-based incentive helps align the utility's interests with customers by providing the utility an income opportunity that grows as the customer value produced by the energy efficiency savings grows. But a performance-based incentive does not eliminate the utility's incentive to keep finding other places and ways in which to increase sales of electricity.
			  o There are several reasons that "lost revenue recovery" is not desirable, such as that the revenue may not actually have been lost and the potential for contentiousness over the level of savings.
			  o A rate case approach will not address the effect of energy efficiency on utility revenues as it is extremely burdensome and likely counter-productive (p. 14, line 14- p. 31, line 10).
			• The Commission should approve a performance based incentive for AmerenUE's achievements under its energy efficiency programs. AmerenUE states that an incentive is important, but is not proposing one at this time in preference to further

			dialogue with parties to this case. NRDC supports a performance-based incentive for AmerenUE as it is one of the key policy supports for strong utility energy efficiency performance (p. 31, line 11-p. 35, line 14). • The Commission should require that AmerenUE establish an independently-run evaluation and verification program. The Commission should include the costs of evaluation and verification in whatever mechanism it adopts to allow AmerenUE to recover energy efficiency costs going forward (p. 35, line 15-p.37, line 10).
223	Direct Testimony of Adam Bickford	Missouri Department of Natural Resources	• DNR supports removing disincentives for electric utilities to invest in DSM programs so that these programs are, at least, revenue neutral (p. 4, lines 5-12). • DNR encourages the Commission to allow expensing of DSM program costs and shareholder incentives to utilities for exemplary performance of DSM programs, which they believe is consistent with SB 376 (2009) (p. 4, line 12- p. 5, line 2). • DNR wants to see more details regarding the DSM tracker proposed by Ameren and how it relates to program costs, energy savings and rate impacts (p. 5, line 4-8). • The following recommendations would be applicable only if a substantial energy savings goal is adopted. (See Laura Wolfe's direct testimony for DNR recommendations on establishing an energy savings goal.) (1) DNR recommends considerations of a performance incentive system that would award a utility 5 percent of net benefits when it realizes 75 percent of its proposed savings goal. (2) DNR also recommends consideration of a maximum performance level of 150 percent or more of a DSM savings goal. Using these two points as goals, DNR proposes a continuous award structure that provides a 1 percent incentive for each 5 percent of performance towards a utility's DSM savings goal. Under this structure, utilities achieving the maximum performance level (i.e. at 150 percent or more of the savings goal), performance awards up to 20 percent should be considered. Performance levels of 100 to 125 percent should have awards in the range of 10 to 15 percent of savings (p. 9, lines 1-20).
224	Direct Testimony of Laura Wolfe	Missouri Department of Natural Resources	• Encourages AmerenUE to increase the levels of savings consistent with other states and consistent with what is learned from their own DSM potential study to be completed by AmerenUE by the end of the year 2009 (p. 3, line 18-p.4., line 2 and p. 9, line 9-p. 11, line 18). • Advises AmerenUE to set an aggressive, achievable goal of energy savings. This can then be used to measure the success of the portfolio of energy efficiency programs that AmerenUE has implemented and will implement (p.7, lines 8-11) • The energy savings goal detailed in Steve Kidwell's testimony for the first three

			program years of its DSM portfolio is 800,000 MWh cumulatively. DNR believes the goal is achievable, but may not be a reasonable long range energy savings goal. DNR believes that electric utilities with established DSM programs in Missouri should set much higher targets for energy savings than this and DNR believes that SB 376 (3009) supports a more aggressive approach to energy efficiency for electric utilities (p. 7, line 8- p. 9, line 8). • DNR recommends that in addition to being informed by its potential study, AmerenUE should model DSM measures that can achieve 1% and 2% of annual energy savings in its next IRP (p. 11, line 18-p.12, line 2).
225	Direct Testimony of Maurice Brubaker	Missouri Industrial Energy Consumers	• As a general proposition, believes it is reasonable for AmerenUE to have an opportunity to earn the same rate of return on both supply-side and demand-side resources. Demand-side resources should be required to meet the same kinds of tests that supply-side resources have to meet to be included in rate base. Among other things, this would mean that the costs were determined to have been prudently incurred and the assets are used and useful (p. 9, line 4-12). • Ten years is an appropriate amortization period (p.9, line 13-p. 13, line 15). • The idea of treating demand-side and supply-side resources comparable extends not only to allowing the utility to earn the same rate of return on the asset, but also extends to the recovery period. The costs of supply-side resources are recovered over their estimated useful life through a provision for depreciation. In the case of demand-side resources, the equivalent asset is a "regulatory asset," and the recovery is by means of an amortization. Thus, depreciation of supply-side resources and amortization of demand-side resources are equivalent concepts that accomplish the same purpose (p. 9, line 17-p. 10, line 14). • Does not support the DSM tracker as proposed by AmerenUE. Reaching forward to include in rate base budgeted amounts for expenditures in 2010 and 2011 that have not been made and which have not created a useful asset, may not be legally permissible. In addition, given the lack of clarity of the explanation of the proposal, the Commission should not give any consideration to this proposal (p. 14, line 1-16). • SB 376 (2009) also includes an "opt-out" provision which allows certain customers not to participate in utility-offered demand-side measures (Section 393.1124.7-10, RSMo). As part of this proceeding, it would be necessary to identify the dollar amounts associated with these programs and determine a credit (for each rate schedule under which eligible customers could be served) that would apply to customers who have elected to opt-out of utility offered programs (p. 15, line 11-p.

			16, line 22).
228	Direct Testimony of Billie Sue Laconte	Missouri Energy Group	• AmerenUE's allowed energy efficiency costs should be collected from customers via a surcharge that is based on the amount of energy efficiency costs spent on each rate class and recognizes that certain customers are exempt (p. 2, lines 2-4).
233	Staff Report Revenue Requirement Cost of Service	MO PSC Staff	• Staff has concerns about the prudence and performance of the Residential Lighting and Appliance Program (L&A) and recommends that the cost of the L&A be left in the regulatory asset and not included in AmerenUE's cost of service for setting rates in this case (p. 43, lines 10-19). • Staff has begun discussions with stakeholders regarding the intent of SB 376 (2009) and plans to develop policies and rules. The Staff recommends that AmerenUE continue the current regulatory asset treatment of demand-side costs until the Commission has established policies and rules to implement SB 376 (2009) (p. 45, lines 27-33). • Many details of the DSM tracker proposed by AmerenUE need to be clarified or determined. Determination of whether a program is cost-effective and efficiency savings have been achieved cannot be made until after the program has both been implemented and evaluated post implementation (p. 46, line 34-p.47, line 19).

State Energy Efficiency Regulatory Frameworks

January 2010

Contents

Spending and budgets for utility-administered electric efficiency programs continue to grow, due in part to the evolution of state policies that allow utilities to pursue efficiency as a sustainable business. **This latest review by IEE staff summarizes ongoing and the most recent policies that promote program cost recovery, lost revenue recovery, and performance incentive mechanisms for electric utilities on a state-by-state basis.**

- The District of Columbia is the latest addition to a growing list of jurisdictions that have adopted revenue decoupling for the electric sector (state summary & map, p. 5). Idaho, Massachusetts, Minnesota, Oregon, Wisconsin and Vermont have also approved decoupling measures in the past two years. Delaware, Hawaii, Michigan, New Hampshire, New Jersey and New Mexico are considering some form of decoupling. Lost revenue adjustment mechanisms were recently approved in Ohio, Oklahoma, North Carolina, and South Carolina as part of larger cost recovery mechanisms. Utah also recently entered the discussion by passing a law that encourages utilities and the Commission to investigate decoupling mechanisms.
- Twenty one states currently have incentives in place, with another seven states pending (p. 11). Colorado, Hawaii, Kentucky, Michigan, Ohio, Oklahoma, North Carolina, Texas, South Carolina, Washington, and Wisconsin have approved new incentive mechanisms in the last two years; Idaho, Indiana, Kansas, Montana, New Mexico, North Carolina, New York, and Utah are each considering some form of performance incentive for efficiency.
- Duke Energy's "virtual power plant" model, which combines cost recovery, lost revenue recovery and incentives into an avoided cost charge, has recently been approved in North Carolina and a decision has been promised soon in South Carolina. The Ohio Commission approved the VPP program in 2008. Duke has proposed similar mechanisms in Indiana and Kentucky.

The Edison Foundation | Institute for Electric Efficiency

Advancing energy efficiency practices and demand response among electric utilities.

State Regulatory Framework Summary Table

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives	Virtual Power Plant
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism		
Alabama	Yes						
Alaska							
Arizona		Yes	Yes			Yes	
Arkansas			Yes				
California	Yes	Yes		Yes		Yes	
Colorado	Yes		Yes		Yes	Yes	
Connecticut		Yes		Yes		Yes	
Delaware	Yes			Pending			
District of Columbia	Yes			Yes			
Florida			Yes				
Georgia	Yes					Yes (one program)	
Hawaii	Yes			Pending		Yes	
Idaho			Yes	Yes		Pending	
Illinois			Yes				
Indiana			Yes	Pending			Pending
Iowa	Yes		Yes				
Kansas	Yes					Pending	
Kentucky			Yes		Yes	Yes	Pending
Louisiana	Yes						
Maine		Yes					
Maryland			Yes	Yes			
Massachusetts		Yes		Yes		Yes	
Michigan			Yes	Pending		Yes	
Minnesota	Yes		Yes	Yes		Yes	
Mississippi	Yes						
Missouri	Yes						
Montana		Yes				Pending	
Nebraska							
Nevada	Yes					Yes	
New Hampshire		Yes		Pending		Yes	

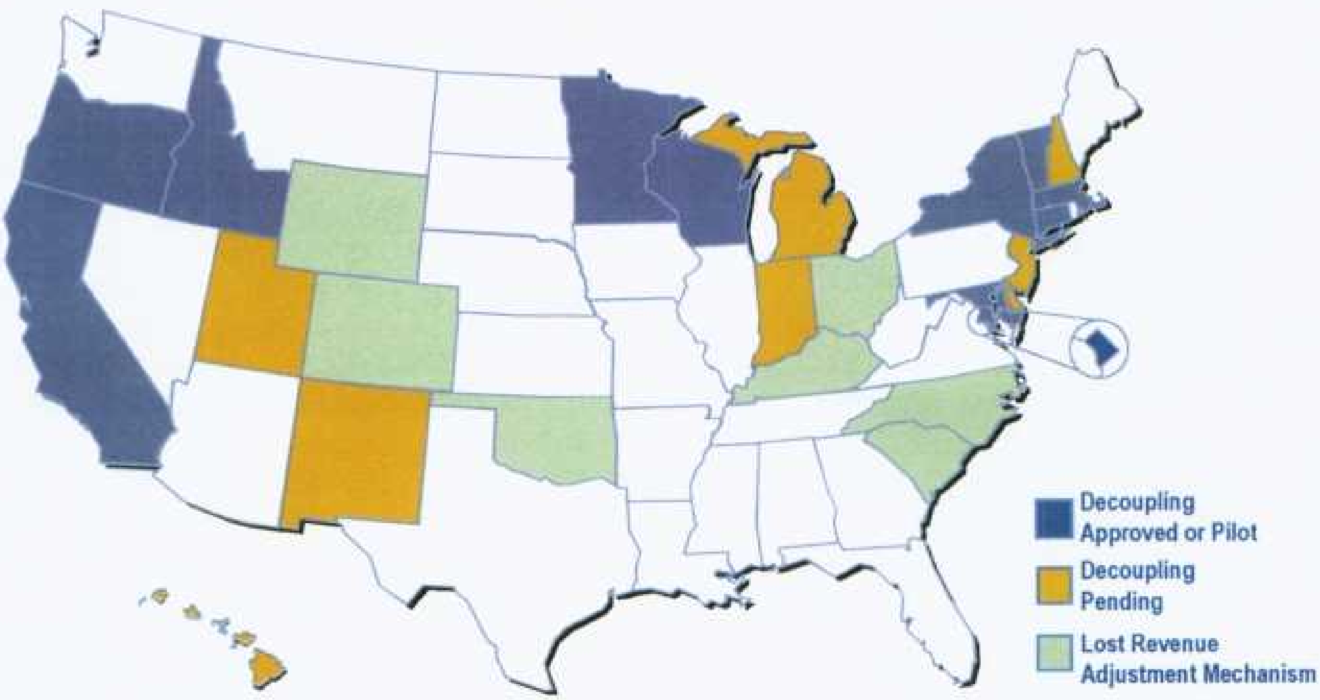
Schedule JAR - 2.2

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives	Virtual Power Plant
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism		
New Jersey		Yes		Pending			
New Mexico			Yes	Pending		Pending	
New York		Yes		Yes		Pending	
North Carolina			Yes		Yes	Yes	Yes
North Dakota							
Ohio			Yes		Yes		Yes
Oklahoma			Yes		Yes	Yes	
Oregon		Yes		Yes			
Pennsylvania	Yes		Yes				
Rhode Island		Yes				Yes	
South Carolina		Yes			Yes	Yes	Pending
South Dakota			Yes				
Tennessee							
Texas	Yes		Yes			Yes	
Utah	Yes		Yes	Pending	Pending	Pending	
Vermont		Yes		Yes		Yes	
Virginia							
Washington		Yes	Yes			Yes	
West Virginia							
Wisconsin	Yes		Yes	Yes		Yes	
Wyoming			Yes		Yes (MDU)		

Please note that although information in this document was compiled from primary sources, readers are encouraged to verify the most recent developments by contacting the appropriate commission or regulatory agency.

For inquiries, please contact Matthew McCaffree, Manager of Electric Efficiency, at mmccaffree@edisonfoundation.net. For further information, please visit http://www.edisonfoundation.net/IEE/.

Lost Revenue Adjustment & Revenue Decoupling Mechanisms for Electric Utilities by State



State	Description	Status	Codes, Orders & Resources
California	California has had some form of decoupling since 1982. The current "decoupling plus" program is a revenue decoupling program combined with performance incentives for meeting or exceeding energy efficiency targets (performance-based rates). Revenue requirements are adjusted for customer growth, productivity, weather, and inflation on an annual basis with rate cases every three or four years (varies by utility). The incentive structure caps penalties/earnings for energy efficiency programs at $450M.	Approved (Decoupling "Plus" approved in 2007)	Code Sec. 9 Section 739(3) and Sec. 10 Section 739.10 as amended by A.B. XI 29; Decisions 98-03-063 & 07-09-043
Colorado (LR)	A conditional portion of the performance incentive mechanism in Colorado (see p. 12) allows for Xcel to recover a $2M after-tax, "disincentive offset" payment for achieving greater than 80% of the annual energy savings goal.	Approved (2007)	HB-07-1037; Decision C08-560, Docket 07A-420E
Connecticut	As of 2007, all electric and gas utilities must include a decoupling proposal as a part of their individual rate cases. The type of decoupling is assigned on a utility-by-utility basis. United Illuminating uses a full decoupling mechanism, adjusted annually. Connecticut Light & Power will submit a proposal for a decoupling mechanism in their next rate case.	Approved (2007)	Public Act No. 07-242

Schedule JAR - 2.5

State	Description	Status	Codes, Orders & Resources
Delaware	The Delaware Commission has recognized decoupling as a possible solution for promoting energy efficiency, but no plans have yet been approved for Delaware utilities. Delmarva Power will submit their decoupling plan in the next rate case in 2009.	Pending	Docket 59
District of Columbia	The DC Public Service Commission approved PEPCO's Bill Stabilization Adjustment (BSA) in October 2009. Like the BSA approved for Maryland, an RPC mechanism is employed which adjusts quarterly.	Approved (2009)	PSC Order 1053-E-549
Hawaii	An order was issued in October 2008 to investigate implementing a decoupling mechanism that could be structured much like that in California. Utilities are required to submit a 2009 test year rate case.	Pending	Docket 2008-0274
Idaho	A three year pilot for a fixed-cost adjustment (an RPC decoupling program) has been instituted and is currently employed by Idaho Power Company. Sales are adjusted for weather and rate increases are capped at 3% over the previous year. The mechanism is only applied to residential and small general service customers.	Approved - Pilot (2007)	PUC IPC-E-09-07, Order No. 30829
Indiana	The Utility Regulatory Commission recently approved Vectren's alternative regulatory plan, which included requests for performance incentives and lost revenue recovery. Vectren's decoupling proposal was rejected, but the commission did request that an alternative lost revenue proposal be submitted. Northern Indiana Power & Light and Indianapolis Power & Light have both proposed lost margin recovery mechanisms and both are pending before Commission.	Pending	Cause No. 43427
Kentucky (LR)	Lost revenue recovery mechanisms are determined on a case-by-case basis, but all electric utilities in Kentucky have DSM proposals in place that include similar lost revenue (LR) recovery due to DSM programs. For these utilities, LR is calculated using the marginal rate, net of variable costs, times the estimated kWh savings from a DSM measure over a three-year period.	Approved (2006)	Statute Ch. 278, Title 285; Docket 2007-00477; 2008-00473
Maryland	A plan to employ revenue decoupling for Maryland utilities under an RPC mechanism was approved in 2007, which adjusts quarterly. The mechanism is similar to the BSA approved for Washington, DC.	Approved (2007)	PSC Case No. 9093; Order 81518
Massachusetts	Gas and electric utilities in Massachusetts must include a decoupling proposal in their next rate case. Target revenues are determined on a utility-wide basis (full decoupling) and can be adjusted for inflation or capital spending requirements if necessary. The Massachusetts DPU expects that all utilities will have fully operational decoupling plans by 2012. In May 2009, National Grid was the first utility to submit a revenue decoupling ratemaking plan (RDR), which proposes an RPC mechanism that adjusts annually.	Approved (2008), full implementation by 2012	Docket 07-50; Docket 09-39

Schedule JAR - 2.6

State	Description	Status	Codes, Orders & Resources
Michigan	Act 295 mandates that the Commission consider decoupling mechanisms proposed by the state's electric utilities. Consumers Energy and Detroit Edison have included decoupling proposals in the rate cases currently before the Commission. A decision in each case is expected in late 2009 or early 2010. Detroit Edison has proposed a revenue decoupling mechanism before the Commission. If approved, the proposed mechanism would normalize lost revenues for weather and have separate adjustments for each customer class.	Pending	Act 295; Case U-15768 and U-15751
Minnesota	A decoupling statute was passed in 2008 that allows for electric and gas utilities to implement decoupling pilot programs of no more than three years. Utilities are required to submit proposals to the state PUC for the structure of recovery mechanisms and frequency of true-ups (none submitted to date). Annual status reports are to be given to the state legislature once the programs are in place.	Approved - Pilot (2008)	Statute 216B.2412
New Hampshire	The New Hampshire PUC concluded in a January 2009 order that existing rate mechanisms are a barrier to energy efficiency. It has ordered that future rate mechanisms be tailored to individual utilities and be normalized for changes in weather, while not specifying the parameters of those mechanisms.	Pending	Order DE 07-064
New Jersey	Atlantic City Electric has proposed a RPC mechanism, or Bill Stabilization Agreement (BSA) as proposed, for their service territory. It is an RPC mechanism that calls for monthly true-ups with changes capped at 10% of previous fixed revenue amounts.	Pending	Docket Eo09010056
New Mexico	HB 305 was signed into law in 2008, requiring that all utilities "include all cost-effective energy efficiency and load management programs in their energy resource portfolios, that regulatory disincentives to public utility development of cost-effective energy efficiency and load management be removed [...]." As a result, the NM Public Regulation Commission is considering proposals for a lost revenue adjustment mechanism that would compensate the utilities based on lost margins through 2010, at which time the PRC may act to remove disincentives to EE through decoupling or other mechanisms (see the incentives summary for more information on the proposed incentive mechanism). A decision is pending.	Pending	HB305, Docket 08-00024-UT
New York	Following an April 2007 order, electric and gas utilities must file proposals for true-up based decoupling mechanisms in ongoing and new rate cases. Proposals have been approved for Consolidated Edison and Orange & Rockland utilities, both for revenue-per-class mechanisms. True-ups occur annually.	Approved (2007)	Cases 03-E-0640, 07-E-0949, & 07-E-0523

State	Description	Status	Codes, Orders & Resources
North Carolina (LR)	The Commission approved a proposed lost revenue adjustment mechanism for Progress Energy Carolinas as part of their cost recovery mechanism. Net lost revenues for each annual period are recovered over 3 years and determined by multiplying lost sales by a net lost revenue rate, which is the difference between the average retail rate applicable to the customer class impacted by the measure and (1) the related customer charge component of that rate, (2) the fuel component of the rate, and (3) the incremental variable O&M rate. True-ups occur annually. The Commission also approved a similar mechanism for Duke Energy Carolinas in December 2009 for energy efficiency measures only, coinciding with the approval of the utility's virtual power plant mechanism.	Approved (2009)	Docket E-2, Sub 931; Docket E-7, Sub 831
Ohio (LR)	As with Kentucky, lost revenue recovery mechanisms are determined on a case-by-case basis. Duke Energy Ohio recovers lost revenues resulting from their portfolio of EE programs through the DSM rider. LR is calculated as the amount of kWh sales lost due to the DSM programs times the energy charge for the applicable rate schedule, less variable costs, divided by the expected kilowatt-hour sales for the upcoming 12 month period. They are collected over a 36 month period. DP&L currently has a case pending. AEP Ohio chose not to seek LR in their prior rate case.	Approved (2007)	ORC §4928.143(B)(2)(h); 06-0091-EL-UNC
Oklahoma (LR)	OG&E has direct lost revenue adjustment ("Class Lost Revenue Factor") built in to the approved demand program rider (DPR) structure, which includes a shared savings mechanism (see p. 15). As the name implies, LR amounts are examined by customer class.	Approved (2009)	Cause No. PUD 200800059, Order 556179
Oregon	Portland General Electric was approved for a two year pilot employing an RPC decoupling mechanism. True-ups will occur annually.	Approved - Pilot (2009)	Order 09-020
South Carolina (LR)	The Commission approved a proposed lost revenue adjustment mechanism for Progress Energy Carolinas as part of their cost recovery mechanism. Net lost revenues for each annual period are recovered over 3 years and determined by multiplying lost sales by a net lost revenue rate, which is the difference between the average retail rate applicable to the customer class impacted by the measure and (1) the related customer charge component of that rate, (2) the fuel component of the rate, and (3) the incremental variable O&M rate. True-ups occur annually.	Approved (2009)	Docket 200-251-E
Utah	HJR 9 was passed into law (March 2009), which includes language supporting decoupling: "[T]he legislature expresses support for regulator mechanisms, which might include performance-based incentives, decoupling fixed cost recovery from sales volume, and other rate designs intended to help remove utility disincentives and create incentives to increase efficiency and conservation... ."	Pending - Law passed, mechanisms yet to be proposed	HJR009

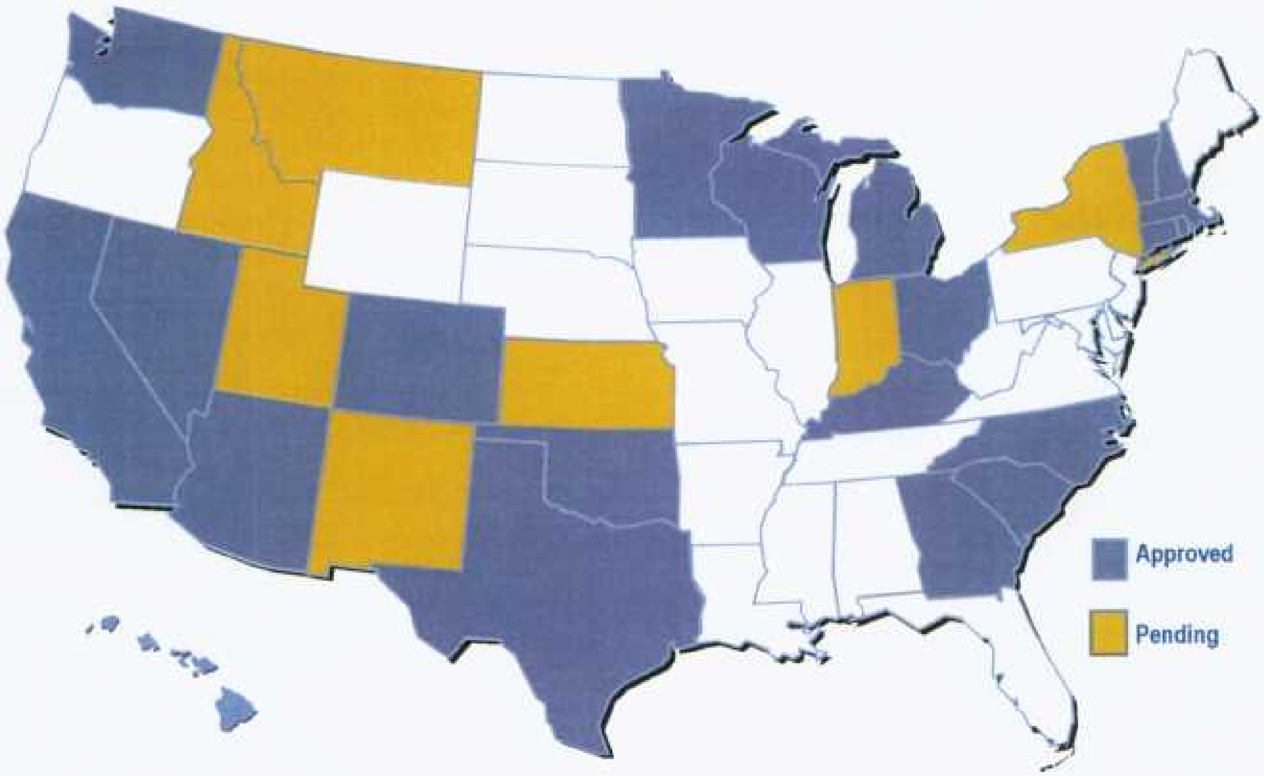
Schedule JAR - 2.8

State	Description	Status	Codes, Orders & Resources
Vermont	An RPC decoupling program was approved for Green Mountain Power under the Alternative Regulation Plan. Rates can be adjusted up to four times per year with an annual reconciliation on allowed earnings. Changes in base rates cannot exceed ~2% per year. CVPS was also approved for decoupling in 2008.	Approved (2007)	Dockets 7175, 7176 & 7336
Wisconsin	Decoupling was approved for WPSC in December 2008 (specified as a "Revenue Stabilization Mechanism"), allowing the utility to pursue a four-year pilot program. WPSC is required to pursue three community-based pilots, which will be regularly reviewed (at 2, 12, 24, and 30 months). True-ups occur annually and over- or under-collection is capped at approximately $14 million. WPL will submit a similar proposal for implementation in 2010.	Approved - Pilot (2008)	Dockets 6680-UR-116 (WPL) & 6690-UR-119 (WPSC)
Wyoming (LR)	A tracking adjustment mechanism that includes direct lost revenue recovery was approved for a small service territory covered by Montana Dakota Utilities. The adjustment applies to all MDU customers to recover costs and lost revenues for load management programs only.	Approved (2007)	Docket No. 20004-65-ET-06

The table of lost revenue recovery mechanims for electric utilities was prepared by the Institute for Electric Efficiency using the latest public data available as of January 11th, 2010. Readers are encouraged to verify the most recent developments in decoupling by contacting the appropriate state regulator or commissioner's office.

For inquiries, please contact Matthew McCaffree, Manager of Electric Efficiency, at mmccaffree@edisonfoundation.net. For further information, please visit http://www.edisonfoundation.net/IEE/.

Performance Incentives for Electric Efficiency by State



State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Arizona	Arizona Public Service (APS) has performance incentives in place under a shared savings mechanism, set at 10% of DSM program net economic benefits and capped at 10% of total DSM expenditures. An APS proposal to modify the incentive mechanism in 2008 requesting recovery of net lost revenues as well as removal of the cap on the incentive was denied.	Approved (2005)	Decision 67744, Docket E-01345A-05-0816, et al
California	California utilities earn an incentive on energy efficiency programs under a shared savings mechanism called an energy efficiency risk-reward incentive mechanism. Revenue from eligible energy efficiency programs is the product of the Earnings Rate (ER) and net benefits. The ER is 12% if the utility achievement towards CPUC goals is greater than 100%, 9% if the goal achievement is between 85 and 100% and 0% if the goal achievement is between 65 and 85%; if the achievement of goals is less than 65%, the utility pays a penalty. Net benefits are calculated as two-thirds of the TRC Net Benefit and one-third of the PAC Net Benefit. In January 2009, the CPUC instituted a rule making (09-01-019) to examine and reform the EE incentive mechanism.	Approved (2007)	R.06-04-010; 09-01-019

Schedule JAR - 2.11

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Colorado	HB 07-1037 (C.R.S. §40-3.2-104) requires investor-owned electric utilities to achieve at least 5% percent reduction of retail energy sales and capacity savings by 2018, based on 2006 sales. The law further states that the Commission shall allow electric DSM investments an opportunity to be more profitable to the utility than any other utility investment that is not already subject to an incentive. The Commission approved the following incentive package to Public Service Colorado: - A "disincentive offset" of $2m/year (after tax) for each year approved DSM plan implemented to offset lost margins; if < 80% of yearly energy goal achieved, the offset may be reduced. - Performance incentives for surpassing "modest" goals; for each 1% of goal reached beyond 80%, company to earn additional 0.2% of net economic benefits, up to 10% at 130% of goal attainment, up to 12% at 150% of goal attainment. Incentives adjusted for 2009 to reflect least-cost planning commitments. - Incentives are allowed via annually trued up DSM Cost Adjustment and are capped at 20% of total annual DSM expenditures.	Approved (2007)	HB-07-1037; Decision C08-560, Docket 07A-420E
Connecticut	The CT PUC requires annual hearings for utilities, where the past year's results for energy savings are reviewed and a performance incentive is determined, which ranges from 1% to 8% of program costs. The minimum threshold of 70% of goals earns the minimum (1%) incentive. Reaching 100% of goals earns 5%, and for reaching 130% of goals earns 8%.	Approved (first in 1988, mechanism changes over time)	Docket 07-10-03
Georgia	Although utilities in Georgia may recover costs and an additional sum for Commission-approved DSM programs, only the Power Credit Single Family Program (Georgia Power) is currently active. The utility may earn an additional sum of 15% of the NPV of the net benefits of the program, contingent on the program achieving at least 50% of projected participation levels.	Approved - Single program only (2007)	Case 24505-U
Hawaii	As part of the state's transition plan to establish a third-party administrator for efficiency programs, the HECO companies are responsible for administering their own DSM programs until the transition date. HECO may earn a shared percentage of savings of 1%-5% with an incentive cap of $2M.	Approved (2008)	Docket & Order 23258, Docket 2007-0323

Schedule JAR - 2.12

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Idaho	Idaho Power (IPC) was approved for a three-year pilot beginning in January 2007 and ending in December 2009. Under the pilot, the Company receives an incentive payment if the market share of homes constructed under the ENERGY STAR Homes Northwest program exceeds a target percentage of new homes constructed. IPC earns an incentive if the program exceeds the market share goal (7% in 2007, 9.8% in 2008, 11.7% in 2009). Incentives are capped at 10% of program net benefits. Penalties are levied if IPC does not meet a minimum market share percentage. On May 14, 2009, it was ordered that Idaho Power neither earn an incentive nor incur a penalty for the ENERGY STAR related program and that the pilot program be discontinued retroactively as of January 1, 2009.	Approved - Pilot (2007); Discontinued (Jan. 1, 2009)	IPC-E-06-32, Order 30268; IPC-E-09-04
Indiana	The state statute allows for either shared savings or adjusted/ bonus ROE mechanisms as DSM incentives. Duke Energy has submitted a proposal for an avoided cost recovery charge for EE programs. Vectren Energy Indiana, Northern Indiana Public Service Company (NIPSCO), and Indianapolis Power and Light have also filed DSM plans requesting performance incentives. All cases are currently pending.	Pending	Administrative Code, Title 170, Art. 4; Cause No. 43374; Cause No. 43427; Cause No. 43618; Cause 43623
Kansas	The State Corporation Commission found that it has "broad authority to provide incentives for energy efficiency" in 2007, but did not specify a mechanism in that order. Kansas Statute 66-117 allows a return of 0.5% to 2% on energy efficiency investments above the allowed rate of return. No plans have yet been approved for any utilities.	Pending; law in place, no programs approved	Docket 08-GIMX-441-GIV; Statute 66-117
Kentucky	State law allows for shareholder incentives through the DSM statute, specifically "incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs." Incentive mechanisms are approved on a case-by-case basis and both Duke Energy and Kentucky Power (AEP) have a shared savings mechanism in place where they receive an incentive of up to 10% of program costs for exceeding goals.	Approved (2007)	Rev. Stat. 278.285(1)(c); Docket 2008-00473; 2007-00477
Massachusetts	The incentive allows utilities to earn about 5% of program costs for energy efficiency programs that meet established program goals. The incentive structure is determined on a program-by-program basis but generally utilizes a three-tiered structure. The first "design performance" level is defined as performance that a Program Administrator expects to achieve in implementing its energy efficiency programs. The second "threshold performance" level is 75% of the design level. The third "exemplary performance" level is 125% of the design level. Incentives are awarded only if a program achieves the threshold level or above.	Approved (2000)	Docket 04-11; Order 98-100

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Michigan	The Commission approved DTE's energy optimization plan in 2009, which includes an incentive mechanism that allows the utility to earn up to 15% of program spending (a cap mandated by PA 295) if they reach 125% of their savings goals. An incentive payment is applied only if DTE exceeds its savings goal. PA 295 contains two provisions authorizing utilities to receive an economic incentive for energy efficiency programs. To be eligible, utilities must request that appropriate energy efficiency program costs be capitalized and earn a normal rate of return. Utilities can request a performance incentive mechanism to provide additional earnings to shareholders if they exceed the annual energy savings target. Incentives are capped at 15% of the total program cost.	Approved (2009)	PA 295 (2008); U-15806
Minnesota	The PUC revised the performance incentive originally approved in 1999. Under the new agreement, utilities retain a portion of net benefits based on the level of achievement, measured as a percent of retail sales. The award scale for this modified shared savings mechanism is calibrated to award \$0.09/kWh at 1.5% of sales (e.g. if a utility achieves savings equal to 1.5% of sales, it will receive \$0.09 for every kWh saved. A final order is pending.	Approved (1999); Revised mechanism (2009)	Docket CI-08-133, Statute 216B.241
Montana	MT statute allows for the Public Service Commission to add 2% to the authorized rate of return for DSM investments. It has not yet been approved for a specific utility.	Passed into law, but not implemented by utility	Code 69-3-712
Nevada	Nevada revised its regulations for IRP and DSM in 2004 to allow utilities to earn as much as 500 basis points above allowed return-on-equity (ROE) for applicable, approved DSM costs (+5%). Utilities must follow approved plans and budgets to earn the incentive amount. The order calls for applying the utility's debt-to-equity ratio to the fraction of capitalized DSM costs, and then applying the extra 5% ROE to that amount.	Approved (2004)	Docket No. 02-5030
New Hampshire	There are two separate incentives in NH. The cost-effectiveness incentive is awarded for programs that achieve a cost effectiveness ratio of 1.0 or higher. The incentive is calculated as 4% of the planned EE budget times the ratio of actual to planned cost effectiveness. The energy savings incentive is awarded when actual lifetime kWh savings are greater than or equal to 65% of projected savings. The incentive is 4% of the planned EE budget times the ratio of actual to planned energy savings. Target incentive amounts are calculated separately for residential and commercial/industrial sectors and are capped at 12% of the planned sector budgets.	Approved (2000)	Order 23.574

Schedule JAR - 2.14

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
New Mexico	A proposed rule making is currently before the PSC that, if approved, would allow utilities to receive an incentive for EE based on energy saved and to receive compensation for revenue lost due to efficiency programs. Additionally, HB 305 was passed in 2008 which requires all utilities to "include all cost-effective energy efficiency and load management programs in the energy resource portfolios."	Pending	Case 08-00024-UT; NM HB 305
New York	New York has recently allowed for performance incentives to be included in utility rate cases and the Commission is in the process of reviewing energy efficiency plans of several NY utilities. The order caps the aggregate incentives at $40M per year statewide and target megawatt-hours will be set for each year at the time of review for the EE plans.	Pending	Case 07-M-0548
North Carolina	North Carolina state law states that a utility may propose incentives for demand side management or energy efficiency programs to the Commission for consideration. The commission approved Progress Energy Carolina's incentive mechanism that allows for an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs. The Commission is considering an avoided cost recovery mechanism submitted by Duke Energy. The Commission issued a notice of decision approving Duke Energy Carolinas' Save-a-Watt program in December 2009 with a full decision to follow in January 2010. The program is similar to that in Ohio, where Duke will receive 50% of the net present value (NPV) of the avoided costs for conservation and 75% of the NPV for demand response.	Approved - Progress Energy Carolinas (2009), Duke Energy (2009)	Docket E-2, sub 931; Docket E-7, Sub 831
Ohio	Duke Energy received approval in December of 2008 for its proposed "Save-a-Watt" program, where the utility will receive 50% of the NPV of the avoided costs for energy conservation and 75% of the NPV of the avoided costs for demand response. Demand response programs are viewed by the parties as having a useful life of 1 year, while energy conservation programs have useful lives of up to 15 years.	Approved (2008)	Docket 08-920-EL-SSO
Oklahoma	A shared savings program has been approved for Public Service Oklahoma (AEP) which allows for two different returns: an incentive of 25% of net savings for programs for which savings can be estimated and 15% of the costs for other programs (e.g. education and marketing programs). OG&E also has an incentive mechanism where they receive shared benefits for achieving savings goals, calculated on a measure-by-measure basis. The utility may earn up to 25% for each measure where the TRC > 1.0 and up to 15% for each measure where the TRC < 1.0.	Approved - PSO (2008), OG&E (2009)	Cause No. PUD 200700449, Order 555302; Cause No. PUD 200800059, Order 556179

Schedule JAR - 2.15

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Rhode Island	The shareholder incentive mechanism includes two components: performance-based metrics for specific program achievements, and kWh savings targets by sector. The program performance metrics are established for each individual program, such as achieving specific savings or a certain market share for the targeted energy-efficient technology. If Narragansett (d/b/a National Grid) achieves the savings goal, it receives 4.4% of the eligible budget. The threshold performance level is 60% of the savings goal. Once the threshold level has been reached, the utility has the ability to earn an additional incentive per kWh saved up to 125% of target savings. Incentive rates change by customer class.	Approved (2005)	Docket 3635, Order 18152
South Carolina	South Carolina law stipulates that the PSC "may adopt procedures that encourage electrical utilities [...] to invest in cost-effective energy efficient technologies and energy conservation programs." The commission approved Progress Energy Carolina's incentive mechanism that allows for an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs. Duke Energy's original avoided cost mechanism was rejected, but the Commission invited re-submission. Duke's EE programs that were proposed separately were approved as of June 1, 2009 with all costs deferred. A modified save-a-watt regulatory model was filed in the summer of 2009. A ruling is expected in early 2010.	Approved for Progress Energy Carolinas (2009); Pending for Duke Energy	Title 58. Public Utilities, Services And Carriers, Chapter 37. Energy Supply And Efficiency; Dockets 2008-251-E (Progress Energy), 2007-358-E, & 2008-251-E (Duke Energy)
Texas	Texas state code specifies that a utility may be awarded a performance bonus (a share of the net benefits) for exceeding established demand reduction goals that do not exceed specified cost limits. Net benefits are the total avoided cost of the eligible programs administered by the utility minus program costs. The performance bonus is based on the utility's energy efficiency achievements for the previous calendar year. If a utility exceeds 100% of its demand reduction goal, the bonus is equal to 1% of the net benefits for every 2% that the demand reduction goal has been exceeded, up to a maximum of 20% of the utility's program costs. A utility that meets at least 120% of its demand reduction goal with at least 10% of its savings achieved through Hard-to-Reach programs receives an additional bonus of 10% of the bonus calculated.	Approved (2008)	PUC of Texas Substantial Rule §25.181(h); CenterPoint Energy Houston Electric 2008 Energy Plan & Report, Project No. 35440
Utah	HJR 9 was approved in March 2009 and includes language supporting incentives: "[T]he legislature expresses support for regulator mechanisms, which might include performance-based incentives, decoupling fixed cost recovery from sales volume, and other rate designs intended to help remove utility disincentives and create incentives to increase efficiency and conservation... ."	Pending - Law passed but no mechanisms proposed	UT HJR009

Schedule JAR - 2.16

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Vermont	The operator of Efficiency Vermont, VEIC, is eligible to receive a performance incentive for meeting or exceeding specific goals established in its contracts. There is also a holdback in the compensation received by VEIC, pending confirmation that contractual goals for savings and other performance indicators have been achieved. The initial contract (2000-2002) allowed incentives of up to 2% of the overall energy efficiency budget over the three-year contract period. Incentives increased to 3.5% of the EE budget for the 2006-2008 period.	Approved (2000)	Contract 0337956, Attachment C
Washington	The Commission approved a shared savings ("Net Shared Incentive") mechanism for Puget Sound Energy in 2006 that either rewards or penalizes PSE for exceeding or not meeting savings targets, respectively. The savings target for 2009 is 278,000 MWh, with a maximum incentive/penalty of +/- 50% and a "dead band" if the utility saves between 90-99.9% of the target. In addition to meeting the overall savings goal, PSE must meet at least 75% of the projected savings targets in both the residential and commercial/industrial sectors. 75% of the full incentive amount will be collected in the year after program implementation, with the remaining amount collected the following year.	Approved (2006)	Docket UE-060266
Wisconsin	As of 2008, Wisconsin Power & Light (Alliant Energy) may earn the same rate-of-return on its investments in energy efficiency made through its "shared savings" program for commercial and industrial customers as it earns on other capital investments. Utilities may propose incentives as part of their rate cases, but there have been no proposals from other utilities under the most recent version of performance incentives. [Note: Wisconsin dropped performance incentives in the 1990s.]	Approved (2008)	Docket 6680-UR-114

Summary of Incentive Mechanisms

Approach	State
Earn a percentage of program costs for achieving savings target	CO, CT, KY, MA, MI, MN, NH, RI, TX, VT, WA
Earn a share of achieved savings	AZ, CA, GA, HI, OK
Earn a percentage of the NPV of avoided costs	NC, OH, SC
Altered rate of return for achieving savings targets	NV, WI

Note: Information on electric efficiency performance incentives was compiled using the latest public data available as of January 11th, 2010. Readers are encouraged to verify the most recent developments by contacting the appropriate commission or regulatory agency. Other resources used in the preparation of this report were ACEEE's State Energy Efficiency Program Database, documents from EPA's National Action Plan on Energy Efficiency, and resources from the Regulatory Assistance Project.

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Schedule JAR - 2.17

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Schedule JAR - 2.18

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<< [Back to Media Releases]

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AMERENUE DONATES 40,000 CFL BULBS TO FOOD PANTRIES-HELPS FAMILIES SAVE ENERGY & MONEY

Jan 26, 2010

AmerenUE announced a new partnership with Operation Food Search (OFS) as another innovative way for UE to reach out to our customers. UE is providing families with ENERGY STAR®-qualified compact fluorescent light bulbs (CFLs) as part of their weekly food packages distributed by OFS. In all, UE will give away 40,000 bulbs to income-qualified St. Louis Metro area families to help them save energy in their homes and money on their electric bills.

More than 40 Missouri pantries were at Operation Food Search to receive the first distribution of bulbs. For those families who don't receive assistance through OFS, they can purchase reduced-price CFLs at more than 100 stores through UE's discount programs. To locate participating stores, go to www.UEfficiency.com.

"CFLs are an easy way for families to cut energy costs and focus resources on other needs. We know in these tough economic times it's important to help our neighbors," said Richard Mark, UE senior vice president, Customer Operations.

ENERGY STAR-qualified CFLs can last up to 10,000 hours or 9 years. They produce 75 percent less heat than traditional bulbs, making them safer to operate and more energy efficient – saving about $30 in electricity costs over the lifetime of the bulb.

About the Partners

AmerenUE, founded in 1902, provides electric and gas service to approximately 1.2 million customers across central and eastern Missouri, including the greater St. Louis area. UE serves 57 Missouri counties and 500 towns. The company's electric rates are among the lowest in the nation. For more information, visit www.amerenue.com.

Since 1981, Operation Food Search has been addressing the growing problem of hunger and poverty in Missouri. Its primary mission of food sourcing and distribution is complemented by innovative fundraising, hunger prevention strategies and new services. For more information, visit www.ofsearch.org.

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St. Peters getting stimulus money for light bulbs, green work

By Shane Anthony
ST. LOUIS POST-DISPATCH
Wednesday, Feb. 10 2010

ST. PETERS — Federal stimulus dollars will come to St. Peters residents this spring in the form of compact fluorescent light bulbs, hydrogen for car tires and other ways to save energy.

City officials plan to use a $512,800 stimulus grant from the Department of Energy to pay for light bulbs, a station that will allow residents to switch the air in their tires for hydrogen, energy efficiency improvements in city buildings and free thermostats for some residents.

The city spent about $37,000 to buy 30,000 bulbs with the grant money, said Ron Darling, the city's health and environmental services manager. He said AmerenUE gave the city an additional 40,000 bulbs, and Cuivre River Electric Cooperative donated 2,700. Volunteers will go door-to-door in April to deliver packages of three light bulbs to each home in the city. The bulbs will be distributed in bags that residents can use for recyclables, Darling said.

Alderman Tommy Roberts, 3rd Ward, said the idea is to use the stimulus money to save money for residents and the city. If the city divided the grant money and passed it out, he said, each resident would receive $9.70. Instead, he said, the residents can save $150 during the lifetime of the three bulbs.

"My vision is that we keep reinvesting the dollars that we've invested from this grant into saving energy in the city of St. Peters," Roberts said.

The program's costs are:

— $228,500 to retrofit city buildings with energy-saving measures suggested by a recent energy audit. City Hall, the Rec-Plex and Recycle City are targeted for energy efficiency upgrades such as new light bulbs, ballast and energy management controls.

— $120,300 for household education, including the distribution of the CFL light bulbs and 600 programmable thermostats. Darling said he would announce the details of the thermostat program later.

Schedule JAR - 4.1

— $120,000 to buy and install solar lighting in the parking lots, marina, general store and pavilions at the new Lakeside 370 Park.

— $43,000 for a semi-self service tire air station where residents can exchange the air in their tires for nitrogen. Darling said nitrogen helps tires stay properly inflated, improving gas mileage. St. Peters expects to have its version running in May.

Darling said residents will get first crack at an expected surplus of about 8,000 bulbs on March 27, when they can exchange burned-out bulbs for new ones at the Home and Garden show at St. Peters City Hall. Residents will receive one CFL for each burned-out incandescent bulb and two CFLs for each burned-out CFL, Darling said. The maximum will be 10 per household as long as supplies last.

Then, on April 10 and 17, volunteers will deliver the three-bulb packages to residents, Darling said.

Roberts said he hoped the city could use the money it saves from energy efficiency upgrades to help make solar and wind energy.

"Eventually, you will see a power plant here in St. Peters," Roberts said. "Wherever it's acceptable, we will have solar, wind and things like that."

Schedule JAR - 4.2