Robin Carnahan
Secretary of State

Administrative Rules Division

Rulemaking Transmittal Receipt

Rule ID: 12165
Date Printed: 10/25/2010
Rule Number: 4 CSR 240-22.050
Rulemaking Type: Proposed Amendment
Date Submitted to Administrative Rules Division: 10/25/2010
Date Submitted to Joint Committee on Administrative Rules: 10/25/2010

Name of Person to Contact with questions concerning this rule:

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Included with Rulemaking:

Cover Letter	10/25/2010
Affidavit for public cost	10/25/2010

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Rule Number 4 CSR 240-22.050

Use a "SEPARATE" rule transmittal sheet for EACH individual rulemaking.

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TYPE OF RULEMAKING ACTION TO BE TAKEN

- ☐ Emergency rulemaking, include effective date
- ☒ Proposed Rulemaking
- ☐ Withdrawal ☐ Rule Action Notice ☐ In Addition ☐ Rule Under Consideration
- ☐ Order of Rulemaking

Effective Date for the Order

☐ Statutory 30 days OR Specific date

Does the Order of Rulemaking contain changes to the rule text? ☐ NO

☐ YES—LIST THE SECTIONS WITH CHANGES, including any deleted rule text:

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SMALL BUSINESS
REGULATORY FAIRNESS BOARD
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Missouri Public Service Commission

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October 25, 2010

Robin Carnahan
Secretary of State
Administrative Rules Division
600 West Main Street
Jefferson City, Missouri 65101

Re: 4 CSR 240-22.050 Demand-Side Resource Analysis

Dear Secretary Carnahan,

CERTIFICATION OF ADMINISTRATIVE RULE

I do hereby certify that the attached is an accurate and complete copy of the proposed rulemaking lawfully submitted by the Missouri Public Service Commission.

The Public Service Commission has determined and hereby certifies that this proposed rulemaking will not have an economic impact on small businesses. The Public Service Commission further certifies that it has conducted an analysis of whether there has been a taking of real property pursuant to section 536.017, RSMo 2000, that the proposed rulemaking does not constitute a taking of real property under relevant state and federal law, and that the proposed rulemaking conforms to the requirements of 1.310, RSMo, regarding user fees.

The Public Service Commission has determined and hereby also certifies that this proposed rulemaking complies with the small business requirements of 1.310, RSMo, in that it does not have an adverse impact on small businesses consisting of fewer than twenty-five full or part-time employees or it is necessary to protect the life, health, or safety of the public, or that this rulemaking complies with 1.310, RSMo, by exempting any small business consisting of fewer than twenty-five full or part-time employees from its coverage, by implementing a federal mandate, or by implementing a federal program administered by the state or an act of the general assembly.

Statutory Authority: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000

Robin Carnahan
Secretary of State
October 25, 2010
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If there are any questions regarding the content of this proposed rulemaking, please contact:

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Morris L. Woodruff

Morris L. Woodruff
Chief Regulatory Law Judge

AFFIDAVIT

PUBLIC COST

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

I, David Kerr, Director, Missouri Department of Economic Development, first being duly sworn, on my oath, state that it is my opinion that the cost of the proposed amendment to rule, 4 CSR 240-22.050, is less than five hundred dollars in the aggregate to this agency, any other agency of state government or any political subdivision thereof.

David D Kerr

David Kerr
Director
Department of Economic Development

Subscribed and sworn to before me this 7th day of Oct, 2010. I am commissioned as a notary public within the County of Cole, State of Missouri, and my commission expires on 17 JULY 2011.

Annette Kehner

ANNETTE KEHNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 17, 2011
Commission Number: 07492656

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Title 4-Department of Economic Development
Division 240-Public Service Commission
Chapter 22-Electric Utility Resource Planning

PROPOSED AMENDMENT

4 CSR 240-22.050 Demand-Side Resource Analysis. The proposed rule deletes sections (2) through (11) of the current rule and adds new sections (2) through (8)

*PURPOSE: This rule specifies the [methods]**principles** by which [end-use measures and]**potential** demand-side[programs]**resource options** shall be developed and [screened]**analyzed** for cost-effectiveness[. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation information to improve program design and cost-effectiveness analysis]**, with the goal of achieving all cost-effective demand-side savings. It also requires the selection of demand-side candidate resource options that are passed on to integrated resource analysis in 4 CSR 240-22.060 and an assessment of their technical potentials and realistic achievable potentials.***

PURPOSE: This proposed amendment allows the utility to determine whether it develops potential demand-side resources using an up/down or down/up analysis. It also allows the utility more latitude in the derivation of avoided costs.

(1) *[Identification of End-Use Measures. The analysis of demand-side resources shall begin with the development of a menu of energy efficiency and energy management measures that]***The utility shall identify a set of potential demand-side resources from which demand-side candidate resource options will be identified for the purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). A potential demand-side resource consists of a demand-side program designed to deliver one or more energy efficiency and energy management measures or a demand-side rate. The utility shall select the set of potential demand-side resources, and describe and document its selection:**

(A) To provide broad coverage of:

[(A) All major customer classes, including at least residential, commercial, industrial and interruptible;]

*[(B)]***1. Appropriate market segments within each major class;**

2. All significant decision-makers, including at least those who choose building design features and thermal integrity levels, equipment and appliance efficiency levels, and utilization levels of the energy-using capital stock;

[*(C) All major end uses, including at least lighting, refrigeration, space cooling, space heating, water heating and motive power]***3. All major end uses, including at least the end uses which are to be considered in the utility's load analysis as listed in 4 CSR 240-22.030(4)(A)1**; and

*[(D)]***4.** Renewable energy sources, **distributed generation resources** and energy technologies **on the customer-side of the meter** that substitute for electricity at the point of use*[.]***;**

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[(2) Calculation of Avoided Costs. The utility shall develop estimates of the cost savings that can be obtained by substituting demand-side resources for existing and new supply-side resources. These avoided cost estimates, expressed in nominal dollars, shall be used for cost-effectiveness screening and ranking of end-use measures and demand-side programs.

(A) Supply Resource Cost Estimates. The utility shall use the cost estimates developed pursuant to 4 CSR 240-22.040(2) to calculate the following two (2) estimates of avoided cost: avoided utility costs and avoided utility costs plus avoided probable environmental costs.

1. The choice of new generation options used to calculate avoided costs shall be limited to those which will meet the need for capacity under the base-case load forecast at approximately the lowest present value of utility revenue requirements over the planning horizon. The utility shall document the basis on which the timing and choice of the new generation options were determined to be approximately least cost.

2. The utility shall calculate the annual capacity cost of each new generation option and new transmission and distribution facilities as the sum of the levelized capital cost per kilowatt-year and the fixed operation and maintenance cost per kilowatt-year.

3. The utility shall calculate the direct running cost of each generation option as the sum of fuel costs, sulfur dioxide emission allowance costs, and variable operation and maintenance costs per kilowatt-hour (kWh). The probable environmental costs calculated pursuant to 4 CSR 240-22.040(2)(B) shall also be expressed on a per-kilowatt hour basis for both existing and new generation resources.

(B) Avoided Cost Periods. The utility shall determine avoided cost periods by grouping hours on a seasonal (for example, summer, winter and transition) and time-of-use basis (for example, on-peak, off-peak, super-peak or shoulder-peak) as required to adequately reflect significant differences in running costs and the type of capacity being utilized to maintain required reserve margins.

(C) Calculation of Avoided Capacity and Running Costs. Avoided costs shall be calculated as the difference in costs associated with a specified decrement in load large enough to delay the on-line date of the new capacity additions by at least one (1) year.

1. Avoided running cost. For each year of the planning horizon and for each avoided cost period, the utility shall calculate the avoided direct running cost per kWh (including sulfur dioxide emission allowance costs) and the avoided probable environmental running cost per kWh due to the specified load decrement.

2. Avoided capacity costs. The utility shall calculate and document the avoided capacity costs per kilowatt-year for each year of the planning horizon.

A. This calculation shall include the costs of any new generation, transmission and distribution facilities that are delayed or avoided because of the specified load decrement.

B. For each year of the planning horizon, the utility shall determine the avoided cost periods in which the avoided new generation, transmission and distribution capacity was utilized, and shall allocate a nonzero portion of the annualized avoided capacity costs to each of the periods in which that capacity was utilized.

(D) Avoided Demand and Energy Costs. The utility shall use the avoided capacity and running costs (appropriately adjusted to reflect reliability reserve margins, demand losses and energy losses) to calculate the avoided demand and energy costs for each avoided cost period. Demand periods shall be defined as the avoided cost periods in which there is a significant probability of a loss of load (for example, periods which require the use of peaking capacity to

maintain power pool reserve margins). Nondemand periods are the avoided cost periods in which there is not a significant probability of a loss of load.

1. Demand period avoided demand costs. Avoided demand costs per kilowatt-year for the demand periods of each season shall include avoided transmission and distribution capacity costs, plus the smaller of the avoided generation capacity cost allocated to the demand period or the avoided capacity cost of peaking capacity.

2. Demand period avoided energy costs. Any capacity cost per kilowatt-year allocated to the demand periods but not included in the avoided demand cost shall be converted to an avoided energy cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated demand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the demand period direct energy costs and the probable environmental energy costs.

3. Nondemand period avoided demand cost. The avoided demand cost for the nondemand periods is zero (0).

4. Nondemand period avoided energy costs. Avoided capacity cost per kilowatt-year allocated to the nondemand periods within each season shall be converted to a per-kilowatt-hour cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated nondemand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the nondemand period direct energy costs and the probable environmental energy costs.

5. Annual avoided demand and energy costs. Annual avoided demand costs shall include avoided transmission and distribution capacity costs, plus the smaller of the annual avoided generation capacity costs or the avoided capacity cost of peaking capacity. Annual avoided energy costs shall include annual avoided running costs plus any avoided capacity costs not included in the annual demand cost.

(3) Cost-Effectiveness Screening of End-Use Measures. The utility shall evaluate the cost-effectiveness of each end-use measure identified pursuant to section (1) using the probable environmental benefits test. All costs and benefits shall be expressed in nominal dollars.

(A) The utility shall develop estimates of the end-use measure demand reduction for each demand period and energy savings per installation for each avoided cost period on a normal-weather basis. If the utility can show that subannual load impact estimates are not required to capture the potential benefits of an end-use measure, annual estimates of demand and energy savings may be used for cost-effectiveness screening.

(B) Benefits per installation of each end-use measure in each avoided cost period shall be calculated as the demand reduction multiplied by the levelized avoided demand cost plus the energy savings multiplied by the levelized avoided energy cost.

1. Avoided costs in each avoided cost period shall be levelized over the planning horizon using the utility discount rate.

2. Annualized benefits shall be calculated as the sum of the levelized benefits over all avoided cost periods.

(C) Annualized costs per installation for each end-use measure shall be calculated as the sum of the following components:

1. Incremental costs of implementing the measure (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate;

2. Incremental annual operation and maintenance costs (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate; and

3. Any probable environmental impact mitigation costs due to implementation of the end-use measure that are borne by either the utility or the customer.

(D) Annualized costs for end-use measures shall not include either utility marketing and delivery costs for demand-side programs or lost revenues due to measure-induced reductions in energy sales or billing demands between rate cases.

(E) Annualized benefits minus annualized costs per installation must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for an end-use measure to pass the screening test. The utility may relax this criterion for measures that are judged to have potential benefits which are not captured by the estimated load impacts or avoided costs.

(F) End-use measures that pass the probable environmental benefits test must be included in at least one (1) potential demand-side program.

(G) For each end-use measure that passes the probable environmental benefits test, the utility also shall perform the utility benefits test for informational purposes. This calculation shall include the cost components identified in paragraphs (3)(C)1. and 2..

(4) The utility shall estimate the technical potential of each end-use measure that passes the screening test.

*(5) The utility shall conduct]***(B) To fulfill the goal of achieving all cost-effective demand-side savings, the utility shall design highly effective potential demand-side programs pursuant to section (A) that broadly cover the full spectrum of cost-effective end-use measures for all customer market segments;**

(C) To include demand-side rates for all customer market segments;

(D) To consider and assess multiple designs for demand-side programs and demand-side rates, selecting the optimal designs for implementation and modifying them as necessary to enhance their performance; and

(E) To include the effects of improved technologies expected over the planning horizon to:

1. Reduce or manage energy use; or

2. Improve the delivery of demand-side programs or demand-side rates.

(2) The utility shall describe and document market research studies, customer surveys, pilot demand-side programs, **pilot demand-side rates,** test marketing programs and other activities as necessary to estimate the technical potential **and realistic achievable potential** of *[end-use measures]***potential demand-side resource options for the utility** and to develop the information necessary to design and implement cost-effective demand-side programs **and demand-side rates**. These research activities shall be designed to provide a solid foundation of information **applicable to the utility** about how and by whom energy-related decisions are made and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency **and energy management impacts.**

[(6) The utility shall develop a set of potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The demand-side program planning and design process shall include at least the following activities and elements:

(A) Identify market segments that are numerous and diverse enough to provide relatively complete coverage of the classes and decision-makers identified in subsections (1)(A) and (B), and that are specifically defined to reflect the primary market imperfections that are common to the members of the market segment;

(B) Analyze the interactions between end-use measures (for example, more efficient lighting reduces the savings related to efficiency gains in cooling equipment because efficient lighting reduces intrinsic heat gain);

(C) Assemble menus of end-use measures that are appropriate to the shared characteristics of each market segment and cost-effective as measured by the screening test; and

(D) Design a marketing plan and delivery process to present the menu of end-use measures to the members of each market segment and to persuade decision-makers to implement as many of these measures as may be appropriate to their situation.

(7) Cost-Effectiveness Screening of Demand-Side Programs. The utility shall evaluate the cost-effectiveness of each potential demand-side program developed pursuant to section (6) using the total resource cost test. The utility cost test shall also be performed for purposes of comparison. All costs and benefits shall be expressed in nominal dollars. The following procedure shall be used to perform these tests:

(A) The utility shall estimate the incremental and cumulative number of program participants and end-use measure installations due to the program and the incremental and cumulative demand reduction and energy savings due to the program in each avoided cost period in each year of the planning horizon.

1. Initial estimates of demand-side program loadimpacts shall be based on the best available information from in-house research, vendors, consultants, industry research groups, national laboratories or other credible sources.

2. As the load-impact measurements required by subsection (9)(B) become available, these results shall be used in the ongoing development and screening of demand-side programs and in the development of alternative resource plans;

(B) In each year of the planning horizon, the benefits of each demand-side program shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost, summed over the avoided cost periods within each year. These calculations shall be performed using the avoided probable environmental costs developed pursuant to section (2);

(C) Utility Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or costs paid by participants in demand-side programs;

(D) Total Resource Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions) plus utility costs to administer, deliver and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or utility incentive payments to customers;

(E) The present value of program benefits minus the present value of program costs over the planning horizon must be positive or the ratio of annualized benefits to annualized costs must be

greater than one (1) for a demand-side program to pass the utility cost test or the total resource cost test. The utility may relax this criterion for programs that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs; and

(F) Potential demand-side programs that pass the total resource cost test shall be considered as candidate resource options and must be included in at least one (1) alternative resource plan developed pursuant to 4 CSR 240-22.060(3).

(8) For each demand-side program that passes the total resource cost test, the utility shall develop time-differentiated load impact estimates over the planning horizon at the level of detail required by the supply system simulation model that is used in the integrated resource analysis required by 4 CSR 240-22.060(4).

(9) Evaluation of Demand-Side Programs. The utility shall develop evaluation plans for all demand-side programs that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(6). The purpose of these evaluations shall be to develop the information necessary to improve the design of existing and future demand-side programs, and to gather data on the implementation costs and load impacts of programs for use in cost-effectiveness screening and integrated resource analysis.

(A) Process Evaluation. Each demand-side program that is part of the utility's preferred resource plan shall be subjected to an ongoing evaluation process which addresses at least the following questions about program design:

1. What are the primary market imperfections that are common to the target market segment?

2. Is the target market segment appropriately defined or should it be further subdivided or merged with other segments?

3. Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target segment?

4. Are the communication channels and delivery mechanisms appropriate for the target segment? and

5. What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each end-use measure included in the program?

(B) Impact Evaluation. The utility shall develop methods of estimating the actual load impacts of each demand-side program included in the utility's preferred resource plan to a reasonable degree of accuracy.

1. Impact evaluation methods. Com-parisons of one (1) or both of the following types shall be used to measure program impacts in a manner that is based on sound statistical principles:

A. Comparisons of preadoption and postadoption loads of program participants, corrected for the effects of weather and other intertemporal differences; and

B. Comparisons between program participants' loads and those of an appropriate control group over the same time period.

2. The utility shall develop load-impact measurement protocols that are designed to make the most cost-effective use of the following types of measurements, either individually or in combination: monthly billing data, load research data, end-use load metered data, building and *equipment simulation models, and survey responses or audit data on appliance and equipment type, size and efficiency levels, household or business characteristics, or energy-related building characteristics.*

(C) The utility shall develop protocols to collect data regarding demand-side program market potential, participation rates, utility costs, participant costs and total costs.

(10) Demand-side programs and load-building programs shall be separately designed and administered, and all costs shall be separately classified so as to permit a clear distinction between demand-side program costs and the costs of load-building programs. The costs of demand-side resource development that also serve other functions shall be allocated between the functions served.

(11) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

(A) A list of the end-use measures developed for initial screening pursuant to the requirements of section (1) of this rule;

(B) The estimated load impacts, annualized costs per installation and the results of the probable environmental benefits test for each end-use measure identified pursuant to section (1);

(C) The technical potential and the results of the utility benefits test for each end-use measure that passes the probable environmental benefits test;

(D) Documentation of the methods and assumptions used to develop the avoided cost estimates developed pursuant to section (2) including:

1. A description of the type and timing of new supply resources, including transmission and distribution facilities, used to calculate avoided capacity costs;

2. A description of the assumptions and procedure used to calculate avoided running costs;

3. A description of the avoided cost periods and how they were determined;

4. A tabulation of the direct running costs and the probable environmental running costs for each avoided cost period in each year of the planning horizon; and

5. A tabulation of the avoided demand cost, the avoided direct energy costs and the avoided probable environmental energy costs for each avoided cost period in each year of the planning horizon;

(E) Copies]. **The utility may compile existing data or adopt data developed by other entities, including government agencies and other utilities, as long as the utility verifies the applicability of the adopted data to its service territory. The utility shall provide copies** of completed market research studies, pilot programs, **pilot rates,** test marketing programs and other studies as required by *[section (5) of]*this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates*[;]***.**

[(F) A description of each market segment identified pursuant to subsection (6)(A);

(G) A description of each demand-side program developed for initial screening pursuant to section (6) of this rule;]

(3) The utility shall develop potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The utility shall

describe and document its potential demand-side program planning and design process which shall include at least the following activities and elements:

(A) Review demand-side programs that have been implemented by other utilities with similar characteristics and identify programs that would be applicable for the utility;

(B) Identify, describe and document market segments that are numerous and diverse enough to provide relatively complete coverage of the major classes and decision-makers identified in section (1)(A) and that are specifically defined to reflect the primary market imperfections that are common to the members of the market segment;

(C) Identify a comprehensive list of end-use measures and demand-side programs considered by the utility, and develop menus of end-use measures for each demand-side program. The demand-side programs shall be appropriate to the shared characteristics of each market segment. The end-use measures shall reflect technological changes in end-uses that may be reasonably anticipated to occur during the planning horizon;

(D) Assess how advancements in metering and distribution technologies that may be reasonably anticipated to occur during the planning horizon affect the ability to implement or deliver potential demand-side programs;

(E) Design a marketing plan and delivery process to present the menu of end-use measures to the members of each market segment and to persuade decision-makers to implement as many of these measures as may be appropriate to their situation. When appropriate, consider multiple approaches for the same menu of end-use measures;

(F) Evaluate statewide marketing and outreach programs, joint programs with natural gas utilities, upstream market transformation programs and other activities. In the event that statewide marketing and outreach programs are preferred, the utilities shall develop joint programs in consultation with the stakeholder group;

(G) Estimate the characteristics needed for the twenty (20) year planning horizon to assess the cost effectiveness of each potential demand-side program, including:

1. An assessment of the demand and energy reduction impacts of each stand-alone end-use measure contained in each potential demand-side program;

2. An assessment of how the interactions between end-use measures, when bundled with other end-use measures in the potential demand-side program, would affect the stand alone end-use measure impact estimates;

3. An estimate of the incremental and cumulative number of program participants and end-use measure installations due to the potential demand-side program;

4. For each year of the planning horizon, an estimate of the incremental and cumulative demand reduction and energy savings due to the potential demand-side program; and

5. For each year of the planning horizon, an estimate of the costs, including:

A. The incremental cost of each stand-alone end-use measure;

B. The cost of incentives paid by the utility to customers to participate in the potential demand-side program. The utility shall consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program, with commensurate adjustments to the technical potential and the realistic achievable potential of that potential demand-side program;

C. The cost of incentives to customers to participate in the potential demand-side program paid by the entities other than the utility;

D. The cost to the customer and to the utility of technology to implement a potential demand–side program;

E. The utility's cost to administer the potential demand-side program; and

F. Other costs identified by the utility.

(H) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs and program participant costs in each year of the planning horizon for each **potential** demand-side program*[developed pursuant to section (6) of this rule;]* **; and**

(I) The *[results of the]*utility *[cost test]***shall describe** and *[the total resource cost test for each demand-side program]***document how it performed the assessments and** developed **the estimates** pursuant to section *([6) of this rule; and*

*(J) A description of the process]***G),** and *[impact evaluation plans for demand-side programs that are included in the preferred resource plan as required by section (9) of this rule]***shall provide documentation of its sources** and *[the results of any such evaluations that have been completed since the utility's last scheduled filing pursuant to 4 CSR 240-22.080]***quality of information.**

(4) The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process, and shall include at least the following activities and elements:

(A) Review demand-side rates that have been implemented by other utilities and identify whether similar demand-side rates would be applicable for the utility taking into account factors such as similarity in electric prices and customer makeup;

(B) Identify demand-side rates applicable to the major classes and decision-makers identified in section (1)(A). When appropriate, consider multiple demand-side rate designs for the same major classes;

(C) Assess how technological advancements that may be reasonably anticipated to occur during the planning horizon, including advanced metering and distribution systems, affect the ability to implement demand-side rates;

(D) Estimate the characteristics needed for the twenty (20) year planning horizon to assess the cost effectiveness of each potential demand-side rate, including:

1. An assessment of the demand and energy reduction impacts of each potential demand-side rate;

2. An assessment of how the interactions between multiple potential demand-side rates, if offered simultaneously, would affect the impact estimates;

3. An assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand-side programs and potential demand-side rates;

4. For each year of the planning horizon, an estimate of the incremental and cumulative demand reduction and energy savings due to the potential demand-side rate;

5. For each year of the planning horizon, an estimate of the costs of each potential demand-side rate, including:

A. The cost of incentives to customers to participate in the potential demand-side rate paid by the utility. The utility shall consider multiple levels of incentives to achieve customer participation in each potential demand-side rate, with commensurate

adjustments to the technical potential and the realistic achievable potentials of that potential demand-side rate;

B. The cost to the customer and to the utility of technology to implement the potential demand-side rate;

C. The utility's cost to administer the potential demand-side rate; and

D. Other costs identified by the utility.

(E) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs and program participant costs in each year of the planning horizon for each potential demand-side program;

(F) Evaluate how each demand-side rate would be considered by the utility's RTO; and

(G) The utility shall describe and document how it performed the assessments and developed the estimates pursuant to section (D), and shall document its sources and quality of information.

(5) The utility shall describe and document its evaluation of the cost-effectiveness of each potential demand-side program developed pursuant to section (3) and each potential demand-side rate developed pursuant to section (4). All costs and benefits shall be expressed in nominal dollars.

(A) In each year of the planning horizon, the benefits of each potential demand-side program and each potential demand-side rate shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost. These calculations shall be performed both with and without the avoided probable environmental costs. The utility shall describe and document the methods, data and assumptions it used to develop the avoided costs.

1. The utility avoided demand cost shall include the capacity cost of generation, transmission and distribution facilities, adjusted to reflect reliability reserve margins and capacity losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. The utility shall describe and document how it developed its avoided demand cost, and the capacity cost chosen shall be consistent throughout the triennial compliance filing.

2. The utility avoided energy cost shall include the fuel costs, emission allowance costs, and variable operation and maintenance costs of generation facilities, adjusted to reflect energy losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. The utility shall describe and document how it developed its avoided energy cost, and the energy costs shall be consistent throughout the triennial compliance filing.

3. The avoided probable environmental costs include the effects of the probable environmental costs calculated pursuant to 4 CSR 240-22.040(2)(B) on the utility avoided demand cost and the utility avoided energy cost. The utility shall describe and document how it developed its avoided probable environmental cost.

(B) The total resource cost test shall be used to evaluate the cost-effectiveness of the potential demand-side programs and potential demand-side rates. In each year of the planning horizon:

1. The costs of each potential demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program

(including both utility and participant contributions) plus utility costs to administer, deliver and evaluate each potential demand-side program;

2. The costs of each potential demand-side rate shall be calculated as the sum of all incremental costs that are due to the rate (including both utility and participant contributions) plus utility costs to administer, deliver and evaluate each potential demand-side rate;

3. For purposes of this test, the costs of potential demand-side programs and potential demand-side rates shall not include lost revenues or utility incentive payments to customers;

4. The costs shall include, but separately identify, the costs of any rate of return or incentive included in the utility's recovery of demand-side program costs.

(C) The utility cost test shall also be performed for purposes of comparison. In each year of the planning horizon:

1. The costs of each potential demand-side program and potential demand-side rate shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver and evaluate each potential demand-side program or potential demand-side rate.

2. For purposes of this test, the costs of potential demand-side programs and potential demand-side rates shall not include lost revenues;

(D) The present value of program benefits minus the present value of program costs over the planning horizon must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for a potential demand-side program or potential demand-side rate to pass the utility cost test or the total resource cost test. The utility may relax this criterion for programs that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs, including programs required to comply with legal mandates;

(E) The utility shall provide results of the total resource cost test and the utility cost test for each potential demand-side program evaluated pursuant to section (5)(B) and for each potential demand–side rate evaluated pursuant to section (5)(C) of this rule, including a tabulation of the benefits (avoided costs), demand-side resource costs and net benefits or costs;

(F) If the utility calculates values for other tests to assist in the design of demand-side programs or demand-side rates, the utility shall describe and document the tests and provide the results of those tests; and

(G) The utility shall describe and document how it performed the cost effectiveness assessments pursuant to section (5), and shall describe and document its methods and its sources and quality of information.

(6) Potential demand-side programs and potential demand-side rates that pass the total resource cost test including probable environmental costs shall be considered as demand-side candidate resource options and must be included in at least one (1) alternative resource plan developed pursuant to 4 CSR 240-22.060(3).

(A) The utility may bundle demand-side candidate resource options into portfolios, as long as the requirements pursuant to section (1) are met and as long as multiple demand-side candidate resource options and portfolios advance for consideration in the integrated

resource analysis in 4 CSR 240-22.060. The utility shall describe and document how its demand-side candidate resource options and portfolios satisfy these requirements.

(B) For each demand-side candidate resource option or portfolio, the utility shall describe and document the time-differentiated load impact estimates over the planning horizon at the level of detail required by the supply system simulation model that is used in the integrated resource analysis, including a tabulation of the estimated annual change in energy usage and in diversified demand for each year in the planning horizon due to the implementation of the candidate demand-side resource option or portfolio.

(C) The utility shall describe and document its assessment of the potential uncertainty associated with the load impact estimates of the demand-side candidate resource options or portfolios. The utility shall estimate:

1. The impact of the uncertainty concerning the customer participation levels by estimating and comparing the technical potential and realistic achievable potential of each demand-side candidate resource option or portfolio.

2. The impact of uncertainty concerning the cost effectiveness by identifying uncertain factors affecting which demand-side resources are cost effective. The utility shall identify how the menu of cost effective demand side measures changes with these uncertain factors and shall estimate how these changes affect the load impact estimates associated with the demand-side candidate resource options.

(7) For each demand-side candidate resource option identified in section (6), the utility shall describe and document the general principles it will use to develop evaluation plans pursuant to 4 CSR 240-22.070(8). The utility shall verify that the evaluation costs in section (5)(B) and (5)(C) are appropriate and commensurate with these evaluation plans and principles.

(8) Demand-side resources and load-building programs shall be separately designed and administered, and all costs shall be separately classified to permit a clear distinction between demand-side resource costs and the costs of load-building programs. The costs of demand-side resource development that also serve other functions shall be allocated between the functions served.

*AUTHORITY: sections 386.040, 386.250, 386.610 and 393.140, RSMo 2000. * Original rule filed June 12, 1992, effective May 6, 1993.*
**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

PUBLIC COST: Adoption of this proposed amendment will not cost affected state agencies or political subdivisions more than $500 in the aggregate.

PRIVATE COST: Adoption of this proposed amendment will cost affected private entities $465,000 in the aggregate.

NOTICE TO SUBMIT COMMENTS AND NOTICE OF PUBLIC HEARING: Anyone may file comments in support of or in opposition to this proposed amendment with the Missouri Public Service Commission, Steve Reed, Secretary of the Commission, P.O. Box 360, Jefferson City, *MO 65102. To be considered, comments must be received at the Commission's offices on or before January 3, 2011, and should include a reference to Commission File No. EX-2010-0254. Comments may also be submitted via a filing using the Commission's electronic filing and information system (EFIS). A public hearing regarding this proposed rule is scheduled for January 6, 2011, at 9:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule, and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.*

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of a Proposed Rulemaking Regarding Revision of the Commission's Chapter 22 Electric Utility Resource Planning Rules	))))	**File No. EX-2010-0254**

DISSENT OF COMMISSIONER JEFF DAVIS TO THE PROPOSED RULEMAKING REVISING THE COMMISSION'S CHAPTER 22 ELECTRIC UTILITY RESOURCE PLANNING RULES

I respectfully dissent from my colleagues' order to promulgate these rules as they are currently written.

Anyone who has ever been involved in the integrated resource planning (IRP) process knows these rules have desperately needed revision for years. It's taken a long time to get where we are. These rules are an improvement in some respects, but something important is missing: accountability for the Public Service Commission and the PSC Staff for any outcome in these IRP proceedings. It may seem like an antiquated note, but I think we need to take responsibility for the decisions we make – or in this case – fail to make.

Both the Missouri Energy Development Association (MEDA) and the Missouri Department of Natural Resources (MDNR) offered language whereby the Commission would at least "acknowledge" the utility's resource plan. "Acknowledgement" of the plan would enhance the process because it would force the parties and the staff to focus on outcomes as well as the process by which those outcomes were determined. After all, outcomes should be the purpose of the IRP process. More importantly, electric utilities could use the acknowledgement process to establish the prudence of making--or not making--certain large capital expenditures that are going to amount to billions of dollars over the next decade (e.g.

– whether to shut down and decommission one or more coal plants or to continue retrofitting all of them) before they get to a rate case and have to argue over imprudence or lack thereof.

Whether and how we address IRP decisions will definitely impact customer rates for years to come. Failing to act on the substance of IRPs constitutes a decision in and of itself. The Commission's failure sends a message of uncertainty to the utilities we regulate, their investors and Wall Street saying either "we want to be free to disavow your plan and disallow the expenses later" or "we are afraid to be criticized for acknowledging a plan that later failed."

Ultimately, our failure to address the substance of utility resource plans increases financing costs for capital investment projects as well as litigation costs in future rate cases because parties will litigate the issue in future cases and knowing the Commission may disallow expenses, lenders and investors will want higher returns. That uncertainty will assuredly cause Missouri investor-owned electric utilities to place the least possible amount of investment capital at risk short-term. This is important because the cheapest plan today will not likely be the cheapest plan over the next one to five years, and even less likely over the long-term (from 30 to 50 years). Thus, the ratepayers could end up paying higher rates long-term so the utility can consistently save a few dollars on the front end, or because the utility opted for cheaper, less reliable technology.

The importance of this issue is best illustrated by the decisions the Commission faces regarding our aging fleet of coal plants. In September, Wood Mackenzie's North American power research group issued a startling report that almost 60 gigawatts of coal-fired electric plants could be retired over the next decade. Independent verification of that estimate comes from Ellen Lapson, Managing Director of Corporate Ratings for Fitch Rating Agency. On

September 30, 2010, at the Financial Research Institute, Director Lapson said that Wood Mackenzie's number was a reasonable number. At least two Commissioners were present at that meeting.

The findings of the Wood Mackenzie report ought to send a shiver down the spine of everyone here at the PSC as well as anyone employed by a Missouri utility. More than 80% of the electricity consumed in this state is fueled by coal. Collectively, Missouri utilities probably own around 10,000 megawatts of coal-fired generation, if not more. Ameren Missouri is the largest Missouri utility and owns several thousand megawatts of coal-fired generation all by itself, but everyone including the utilities who've camouflaged themselves as being leaders in the green revolution have similar risks. So, when the Wall Street analysts say "Coal is in the crosshairs" they mean pretty much every Missouri utility, but especially Ameren because they own the most coal plants, and that ultimately every utility customer in the state is in the crosshairs. Each and every one of our investor-owned electric utilities is going to make significant investment decisions regarding the retirement or retrofitting of a large fleet of coal plants averaging more than 40 years or older as well as the addition of new resources to replace these retiring coal plants, meet growing demand and comply with government mandates for utilities to buy certain amounts of "renewable" electricity.

Presidents and governors don't punt and this Commission shouldn't punt either. Hundreds of millions, if not billions, of dollars are at stake when our electric utilities make these decisions and customer rates are hanging in the balance. We owe it to the ratepayers and to the utilities we regulate to be decisive and thereby meet this Commission's statutory obligation to assure safe and adequate service for consumers at a just and reasonable rate. It's silly and unconscionable to spend a couple of years working on more than 60 pages of rules that force the utility to think of every scenario, to document how every calculation is made, to check to see if the work was performed correctly and then do nothing with such documents except hold them, waiting to whip them out on some unsuspecting utility executive for not following a plan we don't intend to make them follow until the day they deviate from it.

In conclusion, a Commission majority that has shown a willingness to micro-manage electric utilities by requiring them to undertake low-income assistance programs and make our utilities buy Missouri wind-generated electricity ought not have a problem "acknowledging" whether an electric utility's preferred resource plan seems like a good or a bad one.

Respectfully submitted,

Jeffrey N. Davis

Jeff Davis, Commissioner

Dated at Jefferson City, Missouri
On this 25th day of October, 2010.

FISCAL NOTE
PRIVATE COST

I. Department Title: **Missouri Department of Economic Development**
Division Title: **Missouri Public Service Commission**
Chapter Title: **Chapter 22 - Electric Utility Resource Planning**

Rule Number and Title:	4 CSR 240-22.050 Demand-Side Resource Analysis
Type of Rulemaking:	Rule Revision

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the first year cost of compliance with the rule by the affected entities:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities (years 2-4):
4	Investor-owned electric utilities	$465,000	$465,000

III. WORKSHEET

1. KCPL estimated $300,000 additional labor (assumed to be annual costs), $350,000 one time consultant cost and $300,000 consultant cost every 6 years. This results in a KCPL estimated $350,000 annual costs and $300,000 costs every 6 years.
2. Empire estimated $170,000 due to analysis related to rate design and smart grid.
3. AmerenUE estimated $100,000 for the analysis of the smart grid, $150,000 for evaluation of the impacts of energy efficiency that occurs outside of its programs and $200,000 for analysis of rate design impacts.

IV. ASSUMPTIONS

KCPL

- Costs supplied for KCPL are assumed to be for both KCP&L and KCP&L – Greater Missouri Operations Company (GMO).
- $350,000 of the estimated one time cost was estimated for rate planning and design which is already required by the current rule.
- This results in an annual impact of $300,000 and a every 6 year impact of $300,000 (which divided by 6 to get an annual amount is $50,000)

- *Therefore the fiscal impact estimated for KCP&L and GMO is $350,000 annual costs.*

Empire

- Estimated $170,000 due to smart grid and rate design requirements
- Rate design is required by the current rule
- Changes to filing frequency for Empire results in Empire having to meet the full rule requirements every six years instead of the current requirement of every 3 years.
- *Therefore, the fiscal impact estimated for Empire is a cost of $90,000 every 6 years or $15,000 annually.*

AmerenUE

- In its filings to meet the current requirements, AmerenUE states that it includes an evaluation of the impacts of energy efficiency that occurs outside of its programs in its load forecast. Therefore, AmerenUE is currently incurring this cost.
- Rate design is required by the current rule
- AmerenUE gives costs as cost per filing. Staff assumes that this is an annual cost.
- *Therefore, the fiscal impact estimated for AmerenUE is an annual cost of $100,000*

Small Business Regulatory Fairness Board
Small Business Impact Statement

Date: 9-13-2010

Rule Number: 4 CSR 240-22.050

Name of Agency Preparing Statement: Public Service Commission

Name of Person Preparing Statement: Lena Mantle

Phone Number: 573-751-520

Email: Lena.Mantle@psc.mo.gov

Name of Person Approving Statement:

Please describe the methods your agency considered or used to reduce the impact on small businesses *(examples: consolidation, simplification, differing compliance, differing reporting requirements, less stringent deadlines, performance rather than design standards, exemption, or any other mitigating technique).*

Not applicable, no small businesses impacted. Only directly impacts the four investor-owned utility companies in the state.

Please explain how your agency has involved small businesses in the development of the proposed rule.

Not applicable, no small businesses impacted. Only directly impacts the four investor-owned utility companies in the state. However, the MoPSC held stakeholder workshops where any interested entity could participate in the process.

Please list the probable monetary costs and benefits to your agency and any other agencies affected. Please include the estimated total amount your agency expects to collect from additionally imposed fees and how the moneys will be used.

This proposed rule will not cost state agencies or political subdivisions more than $500 in the aggregate.

No additional fees will be collected specifically associated with this rulemaking.

Please describe small businesses that will be required to comply with the proposed rule and how they may be adversely affected.

Not applicable, no small businesses impacted. Only directly impacts the four investor-owned utility companies in the state.

Please list direct and indirect costs (in dollars amounts) associated with compliance.

Not applicable, no small businesses impacted. Only directly impacts the four investor-owned utility companies in the state.

Please list types of business that will be directly affected by, bear the cost of, or directly benefit from the proposed rule.

The four investor-owned electric utilities in the state.

Does the proposed rule include provisions that are more stringent than those mandated by comparable or related federal, state, or county standards?

Yes___ No_X_

If yes, please explain the reason for imposing a more stringent standard.

For further guidance in the completion of this statement, please see §536.300, RSMo.