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June 12, 1992

EX-92-299

The Honorable Roy Blunt
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Attention: Administrative Rules Division

I hereby certify that the attached is an accurate and complete copy of the Proposed Rules lawfully submitted by the Missouri Public Service Commission for filing on this 12th day of June, 1992.

Statutory authority: Sections 386.040, RSMo (1986), 386.250, RSMo (Cum. Supp. 1991), 386.610, RSMo (1986), and 393.140, RSMo (1986).

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BY THE COMMISSION

Brent Stewart

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Executive Secretary

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Encl.

4 CSR 240-22.010 through .080 - Proposed Rules

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Roy D. Blunt

Title 4 - DEPARTMENT OF
ECONOMIC DEVELOPMENT

Division 240 - Public Service Commission

Chapter 22 - Electric Utility Resource Planning

PROPOSED RULES

4 CSR 240-22.010 Policy Objectives

PURPOSE: This rule states the public policy goal that this chapter of rules is designed to achieve, and identifies the objectives that the electric utility resource planning process must serve.

(1) The commission's policy goal in promulgating this chapter of rules is to set minimum standards to govern the scope and objectives of the resource planning process that is required of electric utilities subject to its jurisdiction in order to ensure that the public interest is adequately served. Compliance with these rules shall not be construed to result in commission approval of the utility's resource plans, resource acquisition strategies, or investment decisions.

(2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in a manner that adequately serves the public interest. This objective requires that--

(A) The utility shall consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process;

(B) The utility shall use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan;

(C) The utility shall explicitly identify and, where possible, quantitatively analyze any secondary criteria or considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs. The utility shall document the process and rationale used by decision makers to assess the tradeoffs and determine the appropriate balance between minimization of expected utility costs and these other considerations in selecting the preferred resource plan and

2.

developing contingency options. These considerations shall include, but are not necessarily limited to--

1. Mitigation of risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans;

2. Mitigation of risks associated with new or more stringent environmental laws or regulations that may be imposed at some point within the planning horizon; and

3. Mitigation of rate increases associated with alternative resource plans.

Auth: sections 386.040, RSMo (1986), 386.250, RSMo (Cum. Supp. 1991), 386.610, RSMo (1986), and 393.140, RSMo (1986). Original rule filed June 12, 1992. 1992.

STATE AGENCY COST: See statement following the last Proposed Rule in this chapter.

PRIVATE ENTITY COST: See statement following the last Proposed Rule in this chapter.

NOTICE TO SUBMIT COMMENTS: See notice following the last Proposed Rule in this chapter.

4 CSR 240-22.020 Definitions

PURPOSE: This rule defines terms used in the rules comprising Chapter 22, "Electric Utility Resource Planning".

Editor's Note: The secretary of state has determined that the publication of this rule in its entirety would be unduly cumbersome or expensive. The entire text of the material referenced has been filed with the secretary of state. This material may be found at the Office of the Secretary of State or at the headquarters of the agency and is available to any interested person at a cost not more than the actual cost of reproduction.

(1) Avoided cost means the cost savings obtained by substituting demand-side resources for existing and new supply resources. 4 CSR 240-22.050(3) requires the utility to develop the following measures of avoided cost:

(A) Avoided utility costs developed pursuant to 4 CSR 240-22.050(3)(D), which include energy cost savings plus demand cost savings associated with generation, transmission, and distribution facilities; and

(B) Avoided probable environmental costs developed pursuant to 4 CSR 240-22.050(3)(D) and 4 CSR 240-22.040(2)(B).

(2) Candidate resource options are demand-side programs that pass the screening tests required by 4 CSR 240-22.050(7), or supply-side resources that are not rejected on the basis of the screening analysis required by 4 CSR 240-22.040(2).

(3) Capacity means the maximum capability to continuously produce and deliver electric power via supply-side resources, or the avoidance of the need for such capability by demand-side resources.

(4) A chance node is a decision-tree fork consisting of two (2) or more branches that represent the range and number of relevant potential outcomes for an uncertain factor.

(5) Coincident demand means the hourly demand of a component of system load at the hour of system peak demand within a specified interval of time.

(6) Contingency option means an alternative choice, decision, or course of action designed to enhance the utility's ability to respond quickly and appropriately to events or circumstances that would render the preferred resource plan obsolete.

(7) A decision node is a decision-tree fork consisting of two (2) or more branches that represent the set of decision alternatives being considered by utility planners at that stage of the resource planning process.

(8) A decision tree is a diagram that specifies the order in which key resource decisions must be made, enumerates the set of decision alternatives to be considered at each stage, identifies the critical uncertain factors that affect the outcome of each decision, and shows how the potential range of values for uncertain factors interact with each decision option to affect the expected cost of providing an adequate level and quality of energy services.

(9) Demand means the rate of electric power use, measured in kilowatts (kW).

(10) Demand-side measure is synonymous with end-use measure.

(11) Demand-side resource (or program) means an organized process for packaging and delivering to a particular market segment a portfolio of end-use measures that is broad enough

to include at least some measures that are appropriate for most members of the target market segment.

(12) Driver variable means an external economic or demographic factor that significantly affects some component of utility loads.

(13) Electric utility or utility means any electrical corporation as defined in section 386.020, RSMo (Cum. Supp. 1991) which is subject to the jurisdiction of the commission.

(14) End-use energy service or energy service means the specific need that is served by the final use of energy, such as lighting, cooking, space heating, air conditioning, refrigeration, water heating, or motive power.

(15) End-use measure means an energy-efficiency measure or an energy-management measure.

(16) Energy means the total amount of electric power that is used over a specified interval of time measured in kilowatt-hours (kWh).

(17) Energy-efficiency measure means any device, technology, rate structure, or operating procedure that makes it possible to deliver an adequate level and quality of end-use energy service while using less energy than would otherwise be required.

(18) Energy-management measure means any device, technology, rate structure, or operating procedure that makes it possible to alter the time pattern of electricity usage so as to require less generating capacity, or to allow the electric power to be supplied from more fuel-efficient generating units.

(19) The expected cost of an alternative resource plan is the statistical expectation of the cost of implementing that plan, contingent upon the uncertain factors and associated subjective probabilities represented by chance nodes in the decision tree. 4 CSR 240-22.060 requires the utility to consider probable environmental costs as well as direct utility costs in its assessment of alternative resource plans.

(20) Expected unserved hours means the statistical expectation of the number of hours per year that a utility will be unable to supply its native load without importing emergency power.

(21) Fixed cost margin means the portion of electric energy and demand rates that is designed to recover all non-variable costs.

(22) Implementation plan means descriptions and schedules for the major tasks necessary to implement the preferred resource plan over the implementation period.

(23) Implementation period means the time interval between the filings required of each utility pursuant to 4 CSR 240-22.080.

(24) Inefficient energy-related choice means any decision that causes the life-cycle cost of delivering an adequate level and quality of end-use energy service to be higher than it would be for an available alternative choice.

(25) Inefficient price means a price that is not equal to the long-run marginal cost of providing a good or service.

(26) Information means any fact, relationship, insight, estimate, or expert judgment that narrows the range of uncertainty surrounding key decision variables, or has the potential to substantially influence or alter resource-planning decisions.

(27) Levelized cost means the dollar amount of a fixed annual payment for which a stream of such payments over a specified period of time is equal to a specified present value based on a specified rate of interest.

(28) Life-cycle cost means the present worth of costs over the lifetime of any device or means for delivering end-use energy service.

(29) Load-building program means an organized promotional effort by the utility to persuade energy-related decision makers to choose electricity instead of other forms of energy for the provision of energy service, or to persuade existing customers to increase their use of electricity, either by substituting electricity for other forms of energy or by increasing the level or variety of energy services used. This term is not intended to include the provision of technical or engineering assistance, information about filed rates and tariffs, or other forms of routine customer service.

(30) A load duration curve is a plot of ranked hourly demand versus the number of hours in which demand was greater than or equal to that value over a specified interval of time.

(31) Load factor means the average demand over a specified interval of time divided by the maximum demand in the interval.

(32) Load impact means the change in energy usage and the change in diversified demand during a specified interval of time due to the implementation of a demand-side measure or program.

(33) Load profile means a plot of hourly demand versus chronological hour of the day from the hour ending 1:00 a.m. to the hour ending 12:00 midnight.

(34) Load-research data means average hourly demands (kilowatt-hours per hour) derived from the metered instantaneous demand for each customer in the load-research sample.

(35) Load-research estimates, or class hourly loads, or class load estimates means the statistical expectation of the average hourly demands for each major class derived from the load-research data for that class.

(36) Load-research sample means a subset of utility customers from each major class whose demands are metered to provide statistical estimates of class hourly loads to a specified level of accuracy.

(37) Long run means an analytical framework within which all factors of production are variable.

(38) Lost margin or lost revenues means the reduction between rate cases in billed demand (kW) and energy (kWh) due to installed demand-side measures, multiplied by the fixed-cost margin of the appropriate rate component.

(39) Market imperfection means any factor or situation that contributes to inefficient energy-related choices by decision makers, including at least--

(A) Inadequate information about costs, performance, and benefits of end-use measures;

(B) Inadequate marketing infrastructure or delivery channels for end-use measures;

(C) Inadequate financing options for end-use measures;

(D) Mismatched economic incentives resulting from situations where the person who pays the initial cost of an efficiency investment is different from the person who pays the operating costs associated with the chosen efficiency level;

(E) Ineffective economic incentives when decision makers give low priority to energy-related choices because they have a short-term ownership perspective, or because energy costs are a relatively small share of the total cost structure (for businesses) or of the total budget (for households); or

(F) Inefficient pricing of energy supplies.

(40) Market segment means any subgroup of utility customers (or other energy-related decision makers) which has some or all of the following characteristics in common: they have a similar mix of end-use energy service needs; they are subject to a similar array of market imperfections that tend to inhibit efficient energy-related choices; they have similar values and priorities concerning energy-related choices; or the utility has access to them through similar channels or modes of communication.

(41) Participant means an energy-related decision maker who implements one (1) or more end-use measures as a direct result of a demand-side program.

(42) Planning horizon means a future time period of at least twenty (20) years duration over which the costs and benefits of alternative resource plans are evaluated.

(43) Preferred resource plan means the resource plan that is contained in the resource acquisition strategy that has most recently been adopted for implementation by the electric utility.

(44) The probable environmental benefits test is a test of the cost-effectiveness of end-use measures or demand-side programs that uses the sum of avoided utility costs and avoided probable environmental costs to quantify the net savings obtained by substituting the demand-side resource for supply resources.

(45) Probable environmental cost means the expected cost to the utility of complying with new or additional environmental laws, regulations, taxes, or other costs that utility decision makers judge to have a non-zero probability of being imposed at some point within the planning horizon.

(46) Resource acquisition strategy means a preferred resource plan, an implementation plan, and a set of contingency options for responding to events or circumstances that would render the preferred plan obsolete.

(47) Resource plan means a particular combination of demand-side and supply-side resources to be acquired according to a specified schedule over the planning horizon.

(48) Resource planning means the process by which an electric utility evaluates and chooses the appropriate mix and schedule of supply-side and demand-side resource additions to provide the public with an adequate level, quality, and variety of end-use energy services.

(49) Screening test or cost-effectiveness test means the probable environmental benefits test.

(50) Subjective probability means the judgmental likelihood that the outcome represented by each branch of a chance node will actually occur. The sum of the probabilities associated with the branches of a single chance node must equal one. This means that the specified set of potential outcomes must be exhaustive and mutually exclusive.

(51) Sulfur dioxide emission allowance is an authorization to emit, during or after a specified calendar year, one (1) ton of sulfur dioxide, as defined in Title IV of the Clean Air Act Amendments of 1990, 42 USC 7651a(3).

(52) Supply-side resource or supply resource means any device or method by which the electric utility can provide to its customers an adequate level and quality of electric power supply.

(53) The technical potential of an end-use measure is an estimate of the load impact that would occur if that measure were installed at every location in the utility's service territory where the measure is technically feasible but has not yet been installed.

(54) The utility benefits test is a test of the cost-effectiveness of end-use measures or demand-side programs that uses avoided utility costs to quantify the net savings obtained by substituting the demand-side resource for supply resources.

(55) Utility costs are the costs of operating the utility system and developing and implementing a resource plan that are incurred and paid by the utility. On an annual basis, utility cost is synonymous with utility revenue requirement.

(56) Utility discount rate means the post-tax rate-of-return on net investment used to calculate the utility's annual revenue requirements.

(57) Uncertain factor means any event, circumstance, situation, relationship, causal linkage, price, cost, value, response, or other relevant quantity which can materially affect the outcome of resource planning decisions, about which utility planners and decision makers have incomplete or inadequate information at the time a decision must be made.

(58) Weather measure means a function of daily temperature data that reflects the observed relationship between electric load and temperature.

Auth: sections 386.040, RSMo (1986), 386.250, RSMo (Cum. Supp. 1991), 386.610, RSMo (1986), and 393.140, RSMo (1986). Original rule filed June 12, 1992.

STATE AGENCY COST: See statement following the last Proposed Rule in this chapter.

PRIVATE ENTITY COST: See statement following the last Proposed Rule in this chapter.

NOTICE TO SUBMIT COMMENTS: See notice following the last Proposed Rule in this chapter.

4 CSR 240-22.030 Load Analysis and Forecasting

PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing and forecasting loads, and for the documentation of the inputs, components, and methods used to derive the load forecasts.

(1) Historical Data Base. The utility shall develop and maintain data on the actual historical patterns of energy usage within its service territory. The following information shall be maintained and updated on an ongoing basis.

(A) Customer Class Detail. The historical data base shall be maintained for each of the following major classes: residential; commercial; industrial; interruptible; and other classes that may be required for forecasting (for example, large power, wholesale, outdoor lighting and public authorities).

1. Taking into account the requirement for an unbiased forecast as well as the cost of developing data at the subclass level, the utility shall determine what level of subclass detail is required for forecasting and what

methods to use in gathering subclass information for each major class.

2. The utility shall consider the following categories of subclasses: for residential, dwelling type; for commercial, building or business type; and for industrial, product type. If the utility uses subclasses which do not fit into these categories, it must explain the reasons for its choice of subclasses;

(B) Load Data Detail. The historical load data base shall contain the following data:

1. For each jurisdiction for which the utility makes forecasts, each major class, and to the extent data is required to support the detail specified in (1)(a)1., for each subclass, actual and weather-normalized monthly energy usage and number of customers;

2. For each major class, actual and weather-normalized demands at the time of monthly peaks; and

3. For the system, actual and weather-normalized hourly net system load;

(C) Load Component Detail. The historical data base for major class monthly energy usage and demands at time of monthly peaks shall be disaggregated into a number of units component and a use (kWh) per unit component, for both actual and weather-normalized loads.

1. Typical units for the major classes are--residential, number of customers; commercial, square feet of floor space or commercial employment level; and industrial, production output or employment level. If the utility uses a different unit measure, it must explain the reason for choosing different units.

2. The utility shall develop and implement a procedure to routinely measure and regularly update estimates of the effect of both actual and normal weather on class and system electric loads.

A. The estimates of the effect of weather on class and system loads shall incorporate the non-linear response of loads to daily weather and seasonal variations in loads.

B. For at least the base year of the forecast, the utility shall estimate the cooling, heating, and non-weather-sensitive components of the weather-normalized major class loads.

C. The utility shall document the methods used to develop weather measures and the methods used to estimate the effect of weather on electric loads. If statistical models are used, the documentation shall include at least: the functional form of the models; the estimation techniques employed; the data used to estimate the models, including the development of model input data from basic data; and the statistical results of the models, including parameter estimates and tests of statistical significance; and

(D) Length of Data Base. Once the utility has developed the historical data base, it shall retain that data base for the ten (10) most recent years or for the period of time used as the basis of the utility's forecast, whichever is longer.

1. The development of actual and weather-normalized monthly class and system energy usage and actual hourly net system loads shall start from January of 1982 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer.

2. Actual and weather-normalized class and system monthly demands at the time of the system peak and weather-normalized hourly system loads shall start from January of 1990 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer.

(2) Analysis of Number of Units. For each major class or subclass, the utility shall analyze the historical relationship between the number of units and the economic or demographic factors (driver variables) that affect the number of units for that major class or subclass. These relationships shall be specified as statistical or mathematical models that relate the number of units to the driver variables.

(A) Choice of Driver Variables. The utility shall identify appropriate driver variables as predictors of the number of units for each major class or subclass. The critical factors that influence the driver variables shall also be identified.

(B) Documentation of statistical models shall include the elements specified in (1)(C)2.C. Documentation of mathematical models shall include a specification of the functional form of the equations.

(C) Where the utility has modeled the relationship between the number of units and the driver variables for a major class but not for subclasses within that major class, it shall identify the factors which affect the subclass shares of major class units, and shall explain how those factors were used to predict the subclass shares of the total number of units for the major class.

(3) Analysis of Use Per Unit. For each major class, the utility shall analyze historical use per unit by end use.

(A) End-Use Detail. For each major class, use per unit shall be disaggregated by end use where information permits.

1. Where applicable for each major class, end-use information shall be developed for at least lighting, motor drives, space cooling, space heating, water heating, and refrigeration.

2. For each major class and each end use, including those listed in (3)(A)1., if information is not available, the utility shall provide a schedule for acquiring this end-use information or demonstrate that either the expected costs of acquisition were found to outweigh the expected benefits over the planning horizon or that gathering the end-use information has proven to be infeasible.

3. If the utility has not yet acquired end-use information on space cooling or space heating for a major class, the utility shall determine the effect that weather has on the total load of that major class by disaggregating the load into its cooling, heating and non-weather-sensitive components. If the cooling or heating components are a significant portion of the total load of the major class, then the cooling or heating components of that load shall be designated as end uses for that major class.

4. The difference between the total load of a major class and all end uses for which the utility has acquired end-use information shall be designated as an end use for that major class.

(B) The data base and historical analysis required for each end use shall include at least the following:

1. Measures of the Stock of Energy-Using Capital Goods. For each major class and end use, the utility shall implement a procedure to develop and maintain survey data on the energy-related characteristics of the building, appliance, and equipment stock including saturation levels, efficiency levels, and sizes where applicable. The utility

shall update these surveys before each scheduled filing pursuant to 4 CSR 240-22.080; and

2. Estimates of End-Use Energy and Demand. For each end use, the utility shall estimate end-use energies and demands at time of monthly system peaks, and shall calibrate these energies and demands to equal the weather-normalized monthly energies and demands at time of monthly peaks for each major class for the most recently available data.

(4) Analysis of Load Profiles. The utility shall develop a consistent set of daily load profiles for the most recent year for which data is available. For each month, load profiles shall be developed for a peak weekday, a representative of at least one (1) weekday, and a representative of at least one (1) weekend day.

(A) Load profiles for each day type shall be developed for each end use, for each major class, and for the net system load.

(B) For each day type, the estimated end-use load profiles shall be calibrated to sum to the estimated major class load profiles, and the estimated major class load profiles shall be calibrated to sum to the net system load profiles.

(5) Base-Case Load Forecast. The utility's base-case load forecast shall be based on projections of the major economic and demographic driver variables that utility decision makers believe to be most likely. All components of the base-case forecast shall be based on the assumption of normal weather conditions. The load impacts of implemented demand-side programs shall be incorporated in the base-case load forecast and the load impacts of proposed demand-side programs should not be included in the base-case forecast.

(A) Customer Class and Total Load Detail. The utility shall produce forecasts of monthly energy usage and demands at the time of the summer and winter system peaks by major class for each year of the planning horizon. Where the utility anticipates that jurisdictional levels of forecasts will be required to meet the requirements of a specific state, then the utility shall determine a procedure by which the major class forecasts can be separated by jurisdictional component.

(B) Load Component Detail. For each major class, the utility shall produce separate forecasts of the number of units and use per unit components based on the analysis described in sections (2) and (3) of this rule.

1. Number of Units Forecast. The utility's forecast of number of units for each major class shall be based on the analysis of the relationship between number of units and driver variables described in section (2). Where judgement has been applied to modify the results of a statistical or mathematical model, the utility shall specify the factors which caused the modification and shall explain how those factors were quantified.

A. The forecasts of the driver variables shall be specified and clearly documented. These forecasts shall be compared to historical trends, and significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

B. The forecasts of the number of units for each major class shall be compared to historical trends. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

2. Use Per Unit Forecast. The utility's forecast of monthly energy usage per unit and seasonal peak demands per unit for each major class shall be based on the analysis described in section (3).

A. The forecasts of the driver variables for the use per unit shall be specified. The utility shall document how the forecast of use per unit has taken into account the effects of real prices of electricity, real prices of competitive energy sources, real incomes and any other relevant economic and demographic factors.

B. End-Use Detail. For each major class and for each end use the utility shall forecast both monthly energy use and demands at time of the summer and winter system peaks.

C. The Stock of Energy Using Capital Goods. For each end use for which the utility has developed measures of the stock of energy using capital goods, it shall forecast those measures and document the relationship between the forecasts of the measures to the forecasts of end-use energy and demands at time of the summer and winter system peaks. The values of the driver variables used to generate forecasts of the measures of the stock of energy using capital goods shall be specified and clearly documented.

D. The major class forecasted use per unit shall be compared to historical trends in weather-normalized use per unit. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

(C) Net System Load Forecast. The utility shall produce a forecast of net system load profiles for each year of the planning horizon. The net system load forecast shall be consistent with the utility's forecasts of monthly energy and demands at time of summer and winter system peaks for the major rate classes.

(6) Sensitivity Analysis. The utility shall analyze the sensitivity of the components of the base-case forecast for each major class to variations in the key driver variables, including the real price of electricity, the real price of competing fuels, and economic and demographic factors identified in section (2) and (5)(B)2.A.

(7) High-Case and Low-Case Load Forecasts. Based on the sensitivity analysis described in section (6), the utility shall produce at least two (2) additional load forecasts (a high-growth case and a low-growth case) that bracket the base-case load forecast. Subjective probabilities shall be assigned to each of the load forecast cases. These forecasts and associated subjective probabilities shall be used as inputs to the strategic risk analysis required by 4 CSR 240-22.070.

(8) 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) For each major class specified in (1)(A), the utility shall provide plots of number of units, energy usage per unit, and total class energy usage.

1. Plots shall be produced for the summer period (June through September), the remaining non-summer months, and the calendar year.

2. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

A. The historical period shall include both actual and weather-normalized energy usage per unit and total class energy usage.

B. The plots for the forecast period shall show each end-use component of major class energy usage per unit and total class energy usage for the base-case forecast.

(B) For each major class specified in (1)(A), the utility shall provide plots of class demand per unit and class total demand at time of summer and winter system peak. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

1. The plots for the historical period shall include both actual and weather-normalized class demands per unit and total demands at the time of summer and winter system peak demands.

2. The plots for the forecast period shall show each end-use component of major class coincident demands per unit and total class coincident demands for the base-case forecast.

(C) For the forecast of class energy and peak demands the utility shall provide a summary of the sensitivity analysis required by section (6) of this rule that shows how changes in the driver variables affect the forecast.

(D) For the net system load, the utility shall provide plots of energy usage and peak demand.

1. The energy plots shall include the summer, non-summer and total energy usage for each calendar year.

2. The peak demand plots shall include the summer and winter peak demands.

3. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years. The historical period shall include both actual and weather-normalized values. The forecast period shall include the base-case, low-case, and high-case forecasts.

4. The utility shall describe how the subjective probabilities assigned to each forecast were determined.

(E) For each major class, the utility shall provide estimated load profile plots for the summer and winter system peak days.

1. The plots shall show each end-use component of the hourly load profile.

2. The plots shall be provided for the base year of the load forecast and for the fifth, tenth, and twentieth years of the forecast.

generation technologies; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from utility sources, cogenerators or independent power producers; efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information for each of these potential resource options which shall include at least the following attributes where applicable:

(A) Fuel type, and feasible variations in fuel type or quality;

(B) Practical size range;

(C) Maturity of the technology;

(D) Lead time for permitting, design, construction, testing, and startup;

(E) Capital cost per kilowatt;

(F) Annual fixed operation and maintenance costs;

(G) Annual variable operation and maintenance costs;

(H) Scheduled routine maintenance outage requirements;

(I) Equivalent forced-outage rates or full- and partial-forced-outage rates;

(J) Operational characteristics and constraints of significance in the screening process;

(K) Environmental impacts, including at least the following:

1. Air emissions including at least the primary acid gasses, greenhouse gasses, ozone precursors, particulates, and air toxics;

2. Waste generation including at least the primary forms of solid, liquid, radioactive, and hazardous wastes;

3. Water impacts including direct usage and at least the primary pollutant discharges, thermal discharges, and groundwater effects;

4. Siting impacts and constraints of sufficient importance to affect the screening process; and

(L) Other characteristics that may make the technology particularly appropriate as a contingency option under extreme outcomes for the critical uncertain factors identified pursuant to 4 CSR 240-22.070(2).

(2) Each of the supply-side resource options referred to in section (1) shall be subjected to a preliminary screening analysis. The purpose of this step is to provide an initial ranking of these options based on their relative annualized utility costs as well as their probable environmental costs, and to eliminate from further consideration those options that have significant disadvantages in terms of utility costs, environmental costs, operational efficiency, risk reduction, or planning flexibility, as compared to other available supply-side resource options.

(A) Cost rankings shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs over the useful life of the resource using the utility discount rate.

(B) The probable environmental costs of each supply-side resource option shall be quantified by estimating the cost to the utility of mitigating the environmental impacts of the resource to comply with additional environmental laws or regulations that are likely to be imposed at some point within the planning horizon.

1. The utility shall identify a list of environmental pollutants for which there is, in the judgment of utility decision makers, a non-zero probability that additional laws or regulations will be imposed at some point within the planning horizon.

2. For each pollutant identified pursuant to (2)(B)1. the utility shall specify at least two (2) levels of mitigation beyond existing requirements which are judged to have a non-zero probability of being imposed at some point within the planning horizon.

3. For each mitigation level identified pursuant to (2)(B)2. the utility shall specify a subjective probability that represents utility decision makers' judgment of the likelihood that additional laws or regulations requiring that level of mitigation will be imposed at some point within the planning horizon. Based on these probabilities the utility shall calculate an expected mitigation level for each identified pollutant.

4. The probable environmental cost for a supply-side resource shall be estimated as the joint cost of

simultaneously achieving the expected level of mitigation for all identified pollutants emitted by the resource. The estimated mitigation costs for an environmental pollutant may include or may be entirely comprised of a tax or surcharge imposed on emissions of that pollutant.

(C) The utility shall rank all supply-side resource options identified pursuant to section (1) in terms of both of the following cost estimates: utility costs; and utility costs plus probable environmental costs. The utility shall indicate which supply-side options are considered to be candidate resource options for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). The utility shall also indicate which options are eliminated from further consideration on the basis of the screening analysis and shall explain the reasons for their elimination.

(3) The analysis of supply-side resource options shall include a thorough analysis of existing and planned interconnected generation resources. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the supply resource options under consideration, that the costs of transmission system investments associated with supply-side resources are properly considered, and to provide an adequate foundation of basic information for decisions about the following types of supply-side resource alternatives:

(A) Joint participation in generation construction projects;

(B) Construction of wholly-owned generation or transmission facilities; and

(C) Participation in major refurbishment, upgrading, or retrofitting of existing generation or transmission resources.

(4) The utility shall identify and analyze opportunities for life extension and refurbishment of existing generation plants, taking into account their current condition to the extent that it is significant in the planning process.

(5) The utility shall identify and evaluate potential opportunities for new long-term power purchases and sales, both firm and non-firm, that are likely to be available over all or part of the planning horizon. This evaluation shall be based on an analysis of at least the following attributes of each potential transaction:

(A) Type or nature of the purchase or sale (for example, firm capacity, summer only);

(B) Amount of power to be exchanged;

(C) Estimated contract price;

(D) Timing and duration of the transaction;

(E) Terms and conditions of the transaction, if available;

(F) Required improvements to the utility's generating system, transmission system, or both, and the associated costs; and

(G) Constraints on the utility system caused by wheeling arrangements, whether on the utility's own system or on an interconnected system, or by the terms and conditions of other contracts or interconnection agreements.

(6) For the utility's preferred resource plan selected pursuant to 4 CSR 240-22.070(7), the utility shall determine if additional future transmission facilities will be required to remedy any new generation-related transmission system inadequacies over the planning horizon. If any such facilities are determined to be required, and in the judgment of utility decision makers there is a risk of significant delays or cost increases due to problems in the siting or permitting of any required transmission facilities, this risk shall be analyzed pursuant to the requirements of 4 CSR 240-22.070(2).

(7) The utility shall assess the age, condition, and efficiency level of existing transmission and distribution facilities and shall analyze the feasibility and cost-effectiveness of transmission and distribution system loss-reduction measures as a supply-side resource. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution system, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options.

(8) Before developing alternative resource plans and performing the integrated resource analysis, the utility shall develop ranges of values and probabilities for several important uncertain factors related to supply resources. These values can also be used to refine or verify information developed pursuant to section (2) of this rule. These cost estimates shall include at least the following

elements and shall be based on the indicated methods or sources of information:

(A) Fuel price forecasts over the planning horizon for the appropriate type and grade of primary fuel, and for any alternative fuel that may be practical as a contingency option.

1. Fuel price forecasts shall be obtained from a consulting firm with specific expertise in detailed fuel supply and price analysis or developed by the utility if it has expert knowledge and experience with the fuel under consideration. Each forecast shall consider at least the following factors as applicable to each fuel under consideration:

A. Present reserves, discovery rates, and usage rates of the fuel and forecasts of future trends of these factors;

B. Profitability and financial condition of producers;

C. Potential effect of environmental factors, competition, and government regulations on producers, including the potential for changes in severance taxes;

D. Capacity, profitability, and expansion potential of present and potential fuel transportation options;

E. Potential effects of government regulations, competition, and environmental legislation on fuel transporters;

F. In the case of uranium fuel, potential effects of competition and government regulations on future costs of enrichment services and cleanup of production facilities; and

G. Potential for governmental restrictions on the use of the fuel for electricity production.

2. The utility shall consider the accuracy of previous forecasts as an important criterion in selecting providers of fuel price forecasts.

3. The provider of each fuel price forecast shall be required to identify the critical uncertain factors that drive the price forecast and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty;

(B) Estimated capital costs including engineering design, construction, testing, startup, and certification of new facilities, or major upgrades, refurbishment or rehabilitation of existing facilities.

1. Capital cost estimates shall either be obtained from a qualified engineering firm actively engaged in the type of work required or developed by the utility if it has available other sources of expert engineering information applicable to the type of facility under consideration.

2. The provider of the estimate shall be required to identify the critical uncertain factors that may cause the capital cost estimates to change significantly, and to provide a range of estimates and an associated subjective probability distribution that reflects this uncertainty;

(C) Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities, or for existing facilities that are being upgraded, refurbished, or rehabilitated.

1. Fixed and variable operation and maintenance cost estimates shall be obtained from the same source that provides the capital cost estimates.

2. The critical uncertain factors that affect these cost estimates shall be identified, and a range of estimates shall be provided, together with an associated subjective probability distribution that reflects this uncertainty;

(D) Forecasts of the annual cost or value of sulfur dioxide emission allowances to be used or produced by each generating facility over the planning horizon.

1. Forecasts of the future value of emission allowances shall be obtained from a qualified consulting firm or other source with expert knowledge of the factors affecting allowance prices.

2. The provider of the forecast shall be required to identify the critical uncertain factors that may cause the value of allowances to change significantly, and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty; and

(E) Annual fixed charges for any facility to be included in rate base, or annual payment schedule for leased or rented facilities.

(9) 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 furnish at least the following information:

(A) A summary table showing each supply resource identified pursuant to section (1) and the results of the screening analysis, including--

1. The calculated values of the utility cost and the probable environmental cost for each resource option, and the rankings based on these costs;

2. Identification of candidate resource options that may be included in alternative resource plans; and

3. An explanation of the reasons why each supply-side resource option rejected as a result of the screening analysis was not included as a candidate resource option;

(B) A list of the candidate resource options for which the forecasts, estimates, and probability distributions described in section (8) have been developed or are scheduled to be developed by the utility's next scheduled compliance filing pursuant to 4 CSR 240-22.080;

(C) A summary of the results of the uncertainty analysis that has been completed for candidate resource options described in section (8); and

(D) A summary of the mitigation cost estimates developed by the utility for the candidate resource options identified pursuant to (2)(C). This summary shall include a description of how the alternative mitigation levels and associated subjective probabilities were determined and shall identify the source of the cost estimates for the expected mitigation level.

Auth: sections 386.040, RSMo (1986), 386.250, RSMo (Cum. Supp. 1991), 386.610, RSMo (1986), and 393.140, RSMo (1986). Original rule filed June 12, 1992.

STATE AGENCY COST: See statement following the last Proposed Rule in this chapter.

PRIVATE ENTITY COST: See statement following the last Proposed Rule in this chapter.

NOTICE TO SUBMIT COMMENTS: See notice following the last Proposed Rule in this chapter.

4 CSR 240-22.050 Demand-Side Resource Analysis

PURPOSE: This rule specifies the methods by which end-use measures and demand-side programs shall be developed and screened 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.

(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 provides broad coverage of--

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

(B) 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; and

(D) Renewable energy sources and energy technologies that substitute for electricity at the point of use.

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

(3) 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 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. 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 kilowatt-hour (including sulfur dioxide emission allowance costs), and the avoided probable environmental running cost per kilowatt-hour 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 non-zero 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). Non-demand 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 (3)(C)1. to calculate the demand period direct energy costs and the probable environmental energy costs.

3. Non-Demand Period Avoided Demand Cost. The avoided demand cost for the non-demand periods is zero.

4. Non-Demand Period Avoided Energy Costs. Avoided capacity cost per kilowatt-year allocated to the non-demand 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 non-demand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to (3)(C)1. to calculate the non-demand 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.

(4) 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.

(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 sub-annual 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. 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 that 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 shall also perform the utility benefits test for informational purposes. This calculation shall include the cost components identified in (4)(C).

(5) The utility shall conduct market research studies, customer surveys, pilot demand-side programs, test marketing programs, and other such activities as necessary to estimate the technical potential of end-use measures and to develop the information necessary to design and implement cost-effective demand-side programs.

(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 (1)(A) and (1)(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 utility cost test and the total resource cost test. 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 load impacts 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 (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 (3).

(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.

(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(7). 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 that 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?

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 each demand-side program included in the utility's preferred resource plan to a reasonable degree of accuracy.

1. Impact Evaluation Methods. Comparisons of one 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 pre-adoption and post-adoption loads of program participants, corrected for the effects of weather and other inter-temporal 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 shall be designed and administered, and demand-side program costs shall be classified so as to permit a clear distinction between these costs and the costs of load-building programs to promote increased sales, attract new customers, or induce customers to switch to electricity from other forms of energy supply for the provision of end-use energy services. The costs of demand-side activities 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 (3) 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 of completed market research studies, pilot programs, test marketing programs, and other studies as required by section (5) of this rule, and descriptions of such studies that are planned or in progress and their scheduled completion dates;

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

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

(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 demand-side program developed pursuant to section (6) of this rule;

(I) The results of the utility cost test and the total resource cost test for each demand-side program developed pursuant to section (6) of this rule; and

(J) A description of the process and impact evaluation plans for demand-side programs that are included in the preferred resource plan as required by section (9) of this rule, 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.

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STATE AGENCY COST: See statement following the last Proposed Rule in this chapter.

PRIVATE ENTITY COST: See statement following the last Proposed Rule in this chapter.

NOTICE TO SUBMIT COMMENTS: See notice following the last Proposed Rule in this chapter.

4 CSR 240-22.060 Integrated Resource Analysis

PURPOSE: This rule requires the utility to design alternative resource plans to meet the planning objectives identified in 4 CSR 240-22.010(2), and sets minimum standards for the scope and level of detail required in resource plan analysis, and for the logically consistent and economically equivalent analysis of alternative resource plans.

(1) Resource Planning Objectives. The utility shall design alternative resource plans to satisfy at least the objectives and priorities identified in 4 CSR 240-22.010(2). The utility may identify additional planning objectives that alternative resource plans will be designed to serve.

(2) Specification of Performance Measures. The utility shall specify a set of quantitative measures for assessing the performance of alternative resource plans with respect to identified planning objectives. These measures shall include at least the following: present worth of utility revenue requirements; present worth of probable environmental costs; present worth of out-of-pocket costs to participants in demand-side programs; levelized annual average rates; and maximum single-year increase in annual average rates. All present worth and levelization calculations shall use the utility discount rate. Utility decision makers may also specify other measures that they believe are appropriate for assessing the performance of resource plans relative to the planning goals identified in 4 CSR 240-22.010(2).

(3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of candidate demand-side and supply-side resources to develop a set of alternative resource plans, each of which is designed to achieve one or more of the planning objectives identified in 4 CSR 240-22.010(2). The alternative resource plans developed at this stage of the analysis shall not include load-building programs, which shall be analyzed as required by section (5) of this rule.

(4) Analysis of Alternative Resource Plans. The utility shall assess the relative performance of the alternative resource plans by calculating for each plan the value of each performance measure specified pursuant to section (2). This calculation shall assume values for uncertain factors that are judged by utility decision makers to be most likely. The analysis shall cover a planning horizon of at least twenty (20) years, and shall be carried out with computer models that are capable of simulating the total operation of the system on a year-by-year basis in order to assess the cumulative impacts of alternative resource plans. These models shall be sufficiently detailed to accomplish the following tasks and objectives:

(A) The financial impact of alternative resource plans shall be modeled in sufficient detail to provide comparative estimates of at least the following measures of the utility's financial condition for each year of the planning horizon: pretax interest coverage; ratio of total debt to total capital; and ratio of net cash flow to capital expenditures;

(B) The modeling procedure shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. This provision does not imply any requirement for the utility to file actual rate cases, or for the commission to accord any particular ratemaking treatment to actual costs incurred by the utility;

(C) The modeling procedure shall include a method to ensure that the impact of changes in electric rates on future levels of demand for electric service is accounted for in the analysis; and

(D) The modeling procedure shall treat supply-side and demand-side resources on a logically consistent and economically equivalent basis. This means that the same types or categories of costs, benefits, and risks shall be considered, and that these factors shall be quantified at a similar level of detail and precision for all resource types.

(5) Analysis of Load-Building Programs. If the utility intends to continue existing load-building programs or implement new ones, it shall analyze these programs in the context of one or more of the alternative plans developed pursuant to section (3) of this rule, and using the same modeling procedure and assumptions described in section (4). This analysis shall include the following elements:

(A) Estimation of the impact of load-building programs on the electric utility's summer and winter peak demands and energy usage;

(B) A comparison of annual average rates in each year of the planning horizon for the resource plan with and without the load-building program;

(C) A comparison of the probable environmental costs of the resource plan in each year of the planning horizon with and without the proposed load-building program; and

(D) An assessment of any other aspects of the proposed load-building programs that affect the public interest.

(6) 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 description of each alternative resource plan including the type and size of each resource addition and a listing of the sequence and schedule for retiring existing resources and acquiring each new resource addition;

(B) A summary tabulation that shows the performance of each alternative resource plan as measured by each of the measures specified in section (2) of this rule;

(C) For each alternative resource plan a plot of each of the following over the planning horizon:

1. The combined impact of all demand-side resources on the base-case forecast of summer and winter peak demands;

2. The composition, by program, of the capacity provided by demand-side resources;

3. The composition, by supply resource, of the capacity (including reserve margin) provided by supply resources. Existing supply-side resources may be shown as a single resource;

4. The combined impact of all demand-side resources on the base-case forecast of annual energy requirements;

5. The composition, by program, of the annual energy provided by demand-side resources;

6. The composition, by supply resource, of the annual energy (including losses) provided by supply resources. Existing supply-side resources may be shown as a single resource;

7. The values of the three (3) measures of financial condition identified in (4)(A);

8. Annual average rates;

9. Annual emissions of each environmental pollutant identified pursuant to 4 CSR 240-22.040(2)(B)1; and

10. Annual probable environmental costs.

(D) A discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained;

(E) A description of the computer models used in the analysis of alternative resource plans; and

(F) A description of any proposed load-building programs, a discussion of why such programs are judged to be in the public interest, and for all resource plans that include such programs, plots of the following over the planning horizon:

1. Annual average rates with and without the load-building programs; and

2. Annual utility costs and probable environmental costs with and without the load-building programs.

Auth: sections 386.040, RSMo (1986), 386.250, RSMo (Cum. Supp. 1991), 386.610, RSMo (1986), and 393.140, RSMo (1986). Original rule filed June 12, 1992.

STATE AGENCY COST: See statement following the last Proposed Rule in this chapter.

PRIVATE ENTITY COST: See statement following the last Proposed Rule in this chapter.

NOTICE TO SUBMIT COMMENTS: See notice following the last Proposed Rule in this chapter.

<u>4 CSR 240-22.070 Risk Analysis and Strategy Selection</u>

PURPOSE: This rule requires the utility to identify the critical uncertain factors that affect the performance of resource plans, establishes minimum standards for the methods used to assess the risks associated with these uncertainties, and requires the utility to specify and officially adopt a resource acquisition strategy.

(1) The utility shall use the methods of formal decision analysis to assess the impacts of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3), to analyze the risks associated with alternative resource plans, to quantify the value of better information concerning the critical uncertain factors, and to explicitly state and document the subjective probabilities that utility decision makers assign to each of these uncertain factors. This assessment shall include a decision tree representation of the key decisions and uncertainties associated with each alternative resource plan.

(2) Before developing a detailed decision tree representation of each resource plan the utility shall conduct a preliminary sensitivity analysis to identify the uncertain factors that are critical to the performance of the resource plan. This analysis shall assess at least the following uncertain factors:

(A) The range of future load growth represented by the low-case and high-case load forecasts;

(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital;

(C) Future changes in environmental laws, regulations, or standards;

(D) Relative real fuel prices;

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities;

(F) Construction costs and schedules for new generation and transmission facilities;

(G) Purchased power availability, terms, and cost;

(H) Sulfur dioxide emission allowance prices;

(I) Fixed operation and maintenance costs for existing generation facilities;

(J) Equivalent or full- and partial-forced-outage rates for new and existing generation facilities;

(K) Future load impacts of demand-side programs; and

(L) Utility marketing and delivery costs for demand-side programs.

(3) For each alternative resource plan, the utility shall construct a decision tree diagram that appropriately represents the key resource decisions and critical uncertain factors that affect the performance of the resource plan.

(4) The decision tree diagram for all alternative resource plans shall include at least two (2) chance nodes for load growth uncertainty over consecutive sub-intervals of the planning horizon. The first such sub-interval shall be not more than ten (10) years long.

(5) The utility shall use the decision tree formulation to compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2), contingent upon the identified uncertain factors and associated subjective probabilities assigned by utility decision makers pursuant to section (1) of this rule. Both the expected performance and the risks of each alternative resource plan shall be quantified.

(A) The expected performance of each resource plan shall be measured by the statistical expectation of the value of each performance measure.

(B) The risk associated with each resource plan shall be characterized by some measure of the dispersion of the probability distribution for each performance measure, such as the standard deviation or the values associated with specified percentiles of the distribution.

(6) The impact of the preferred resource plan on future requirements for emergency imported power shall be explicitly modeled and quantified. The requirement for emergency imported power shall be measured by expected unserved hours under normal-weather load conditions.

(A) The daily normal weather series used to develop normal-weather loads shall contain a representative amount of day-to-day temperature variation. Both the high and low extreme values of daily normal weather variables shall be consistent with the historical average of annual extreme temperatures.

(B) The supply-system simulation software used to calculate expected unserved hours shall be capable of accurately representing at least the following aspects of system operations:

1. Chronological dispatch, including unit commitment decisions that are consistent with the operational characteristics and constraints of all system resources;

2. Heat rates, fuel costs, variable operation and maintenance costs, and sulfur dioxide emission allowance costs for each generating unit;

3. Scheduled maintenance outages for each generating unit;

4. Partial- and full-forced-outage rates for each generating unit; and

5. Capacity and energy purchases and sales, including the full spectrum of possibilities, from long-term firm contracts or unit participation agreements to hourly economy transactions.

A. The utility shall maintain the capability to model purchases and sales of energy both with and without the inclusion of sulfur dioxide emission allowances.

B. The level of energy sales and purchases shall be consistent with forecasts of the utility's own production costs as compared to the forecasted production costs of other likely participants in the bulk power market; and

(C) The utility may use an alternative method of calculating expected unserved hours per year if it can demonstrate that the alternative method produces results that are equivalent to those obtained by a method that meets the requirements of (6)(B).

(7) The utility shall select a preferred resource plan from among the alternative plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060 and sections (1)-(6) of this rule. The preferred resource plan shall satisfy at least the following conditions:

(A) In the judgment of utility decision makers, the preferred plan shall strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2); and

(B) The trend of expected unserved hours for the preferred resource plan must not indicate a consistent increase in the need for emergency imported power over the planning horizon.

(8) The utility shall quantify the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by the present value of utility revenue requirements.

(9) The utility shall develop an implementation plan that specifies the major tasks and schedules necessary to implement the preferred resource plan over the implementation period. The implementation plan shall contain--

(A) A schedule and description of ongoing and planned research activities to update and improve the quality of data used in load analysis and forecasting;

(B) A schedule and description of ongoing and planned demand-side programs, program evaluations, and research activities;

(C) A schedule and description of all supply-side resource acquisition and construction activities; and

(D) Identification of critical paths and major milestones for each resource acquisition project, including decision points for committing to major expenditures.

(10) The utility shall develop, document, and officially adopt a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by the board of directors, a committee of senior management, an officer of the company, or other responsible party who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:

(A) A preferred resource plan selected pursuant to the requirements of section (7) of this rule;

(B) An implementation plan developed pursuant to the requirements of section (9) of this rule;

(C) A specification of the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate, and an explanation of how these limits were determined;

(D) A set of contingency options that are judged to be appropriate responses to extreme outcomes of the critical uncertain factors, and an explanation of why these options are judged to be appropriate responses to the specified outcomes; and

(E) A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency options when the specified limits for uncertain factors are exceeded.

(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 furnish at least the following information:

(A) A decision tree diagram for each of the alternative resource plans along with narrative discussions of the following aspects of the decision analysis:

1. A discussion of the sequence and timing of the decisions represented by decision nodes in the decision

tree, and a description of the specific decision alternatives considered at each decision point; and

2. An explanation of how the critical uncertain factors were identified, how the ranges of potential outcomes for each uncertain factor were determined, and how the subjective probabilities for each outcome were derived;

(B) Plots of the cumulative probability distribution of each performance measure for each alternative resource plan;

(C) For each performance measure, a table that shows the expected value and the risk of each resource plan;

(D) A plot of the expected level of annual unserved hours for the preferred resource plan over the planning horizon;

(E) A discussion of the analysis of the value of better information required by section (8), a tabulation of the key quantitative results of that analysis, and a discussion of how those findings will be incorporated in ongoing research activities;

(F) A discussion of the process used to select the preferred resource plan, including the relative weights given to the various performance measures, and the rationale used by utility decision makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk; and

(G) The fully documented resource acquisition strategy that has been developed and officially adopted pursuant to the requirements of section (10) of this rule.

Auth: sections 386.040, RSMo (1986), 386.250, RSMo (Cum. Supp. 1991), 386.610, RSMo (1986), and 393.140, RSMo (1986). Original rule filed June 12, 1992.

STATE AGENCY COST: See statement following the last Proposed Rule in this chapter.

PRIVATE ENTITY COST: See statement following the last Proposed Rule in this chapter.

NOTICE TO SUBMIT COMMENTS: See notice following the last Proposed Rule in this chapter.

4 CSR 240-22.080 Filing Schedule and Requirements

PURPOSE: This rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of this chapter of rules. The purpose of the compliance review required by this chapter of rules is not commission approval of the substantive findings, determinations, or analyses contained in the filing. The purpose of the compliance review required by this chapter is to determine whether the utility's resource acquisition strategy meets the planning objectives stated in 4 CSR 240-22.010(2)(A)-(C).

(1) Each electric utility which sold more than one million (1,000,000) megawatt-hours to retail electric customers for calendar year 1991 as identified in the annual reports on file with the Commission shall make a filing with the commission every three (3) years that demonstrates compliance with the provisions of this chapter of rules. The utility's filing shall include at least the following items:

(A) Letter of transmittal;

(B) Summary information and any press release related to the filing;

(C) Reports and information required by 4 CSR 240-22.030(8), 4 CSR 240-22.040(9), 4 CSR 240-22.050(11), 4 CSR 240-22.060(6), and 4 CSR 240-22.070(11);

(D) A narrative description and summary of the reports and information referred to in (1)(C). The narrative shall specifically show that the resource acquisition strategy contained in the filing has been officially approved by the utility, and that the methods used and the procedures followed by the utility in formulating the resource acquisition strategy comply with the provisions of this chapter of rules;

(E) A request for a protective order from the commission if the utility seeks to protect anything contained in the filing as trade secrets, or as confidential or private technical, financial, or business information; and

(F) Tariff sheets as required by 4 CSR 240-14.040(2) for demand-side programs that are promotional practices as defined by 4 CSR 240-14.010(6)(L).

(2) The electric utility's compliance filing may also include a request for non-traditional accounting procedures and information regarding any associated ratemaking

treatment to be sought by the utility for demand-side resource costs. If the utility desires to make any such request, it must be made in the utility's compliance filing pursuant to this rule and not at some subsequent time. If the utility desires to continue any previously authorized non-traditional accounting procedures beyond the three (3) year implementation period, it must request reauthorization in each subsequent filing pursuant to this rule. Commission authorization of any non-traditional accounting procedures does not constitute a finding that the expenditures involved are reasonable or prudent, and should not be construed as approval or acceptance of any item in any account for the purpose of fixing rates. Any request for initial authorization or reauthorization of such non-traditional accounting procedures must--

(A) Be limited to specific demand-side programs that are included in the utility's implementation plan; and

(B) Include specific proposals that contain at least the following information:

1. An explanation of the specific form and mechanics of implementing the proposed accounting procedure and any associated ratemaking treatment to be sought;

2. A discussion of the rationale and justification of the need for a non-traditional treatment of such costs;

3. An explanation of how the specific proposal meets this need for non-traditional treatment; and

4. A quantitative comparison of the utility's estimated earnings over the three (3) year implementation period with and without the proposed non-traditional accounting procedures and any associated ratemaking treatment to be sought.

(3) The electric utilities shall make their initial compliance filings on a staggered basis in order of decreasing size of gross annual operating revenues as identified in the annual reports on file with the commission for calendar year 1991. The electric utility with the largest gross annual operating revenues shall make its initial filing seven (7) months after the effective date of this chapter of rules. The remaining electric utilities shall make their initial filings in successive increments of seven (7) months from the effective date of this chapter of rules.

(4) The commission will establish a docket for the purpose of receiving the compliance filing of each affected electric

utility. The commission will issue an order that establishes an intervention deadline, sets an early prehearing conference, and provides for notice.

(5) The staff shall review each compliance filing required by this rule and shall file a report not later than one hundred twenty (120) days after each utility's scheduled filing date that identifies any deficiencies in the electric utility's compliance with the provisions of this chapter of rules, any major deficiencies in the methodologies or analyses required to be performed by this chapter of rules, and any other deficiencies which the staff in its limited review determines would cause the electric utility's resource acquisition strategy to fail to meet the planning objectives identified in 4 CSR 240-22.010(2)(A)-(C). If the staff's limited review finds no deficiencies, the staff report shall so state. A staff report that finds that an electric utility's filing is in compliance with this chapter of rules shall not be construed as acceptance or agreement with the substantive findings, determinations, or analysis contained in the electric utility's filing.

(6) Also within one hundred twenty (120) days after an electric utility's compliance filing pursuant to this rule, the office of public counsel and any intervenor may file a report or comments based on a limited review that identify any deficiencies in the electric utility's compliance with the provisions of this chapter of rules, any deficiencies in the methodologies or analyses required to be performed by this chapter of rules, and any other deficiencies which the public counsel or intervenor believes would cause the utility's resource acquisition strategy to fail to meet the planning objectives identified in 4 CSR 240-22.010(2)(A)-(C).

(7) All workpapers, documents, reports, data, computer model documentation, analysis, letters, memoranda, notes, test results, studies, recordings, transcriptions and any other supporting information relating to the filed resource acquisition strategy within the electric utility's or its contractors' possession, custody or control shall be preserved and made available in accordance with any protective order to the staff, public counsel, and any intervenor for use in its review of the periodic filings required by this rule. Each electric utility shall retain at least one (1) copy of the officially adopted resource acquisition strategy and all supporting information for at least ten (10) years.

(8) If the staff, public counsel, or any intervenor finds deficiencies, it shall work with the electric utility and the other parties to reach, within forty-five (45) days of

the date that the report or comments were submitted, a joint agreement on a plan to remedy the identified deficiencies. If full agreement cannot be reached, this should be reported to the commission through a joint filing as soon as possible, but no later than forty-five (45) days after the date on which the report or comments were submitted. The joint filing should set out in a brief narrative description those areas on which agreement cannot be reached.

(9) If full agreement on remedying deficiencies is not reached, then within sixty (60) days from the date on which the staff, public counsel, or any intervenor submitted a report or comments relating to the electric utility's compliance filing, the electric utility may file a response and the staff, public counsel, and any intervenor may file comments in response to each other. The commission will issue an order which indicates on what items, if any, a hearing will be held and which establishes a procedural schedule.

(10) If the utility determines that circumstances have changed so that the preferred resource plan is no longer appropriate, either due to the limits identified pursuant to 4 CSR 240-22.070(10)(C) being exceeded or for other reasons, the utility shall notify the commission in writing within sixty (60) days of the utility's determination. If the utility decides to implement any of the contingency options identified pursuant to 4 CSR 240-22.070(10)(D), the utility shall file for review a revised implementation plan in advance of its next regularly scheduled compliance filing.

(11) Upon written application, and after notice and an opportunity for hearing, the commission may waive or grant a variance from a provision of this chapter of rules for good cause shown.

(A) The granting of a variance to one (1) electric utility which waives or otherwise affects the required compliance with a provision of this chapter of rules does not constitute a waiver respecting, or otherwise affect, the required compliance of any other electric utility with a provision of these rules.

(B) The commission will not waive or grant a variance from this chapter of rules in total.

(12) The commission may extend or reduce any of the time periods specified in this rule for good cause shown.

(13) The commission will issue an order which contains findings that the electric utility's filing pursuant to this rule either does or does not demonstrate compliance with the

requirements of this chapter of rules, and that the utility's resource acquisition strategy either does or does not meet the planning objectives stated in 4 CSR 240-22.010(2)(A)-(C), and which addresses any utility requests pursuant to section (2) for authorization or reauthorization of non-traditional accounting procedures for demand-side resource costs.

Auth: sections 386.040, RSMo (1986), 386.250, RSMo (Cum. Supp. 1991), 386.610, RSMo (1986), and 393.140, RSMo (1986). Original rule filed June 12, 1992.

STATE AGENCY COST: These Proposed Rules directly impact without any discretion only the Public Service Commission. Other state agencies and certain political subdivisions may choose to participate in proceedings resulting from these proposed rules and thereby incur costs voluntarily. These Proposed Rules will not cost state agencies or political subdivisions more than $500 in the aggregate for the period February 1, 1993 through June 30, 1993. These Proposed Rules are estimated to cost the Commission $50,000 and the Office of the Public Counsel $30,000 for outside consultant services for the period July 1, 1993 through June 30, 1994. A fiscal note containing this estimated cost of compliance and the assumptions on which it is based has been filed with the Secretary of State.

PRIVATE ENTITY COST: These Proposed Rules are estimated to cost the five (5) investor-owned electrical corporations that sold more than one million (1,000,000) megawatt-hours in calendar year 1991 an aggregate one-time cost of $9,841,000, a cost of $3,383,000 (excluding the one-time cost) for the period February 1, 1993 through June 30, 1993, and a cost of $8,268,000 (excluding the one-time cost) for the period July 1, 1993 through June 30, 1994. Allocating the aggregate one-time cost to the fiscal year 1993 and the fiscal year 1994 periods results in an aggregate cost of $6,633,000 for the period February 1, 1993 through June 30, 1993, and an aggregate cost of $13,056,000 for the period July 1, 1993 through June 30, 1994. These estimated costs are principally based on figures provided by the affected investor-owned electrical corporations. Some gas utilities believe that they could be exposed to a significant reduction in income as a result of losing load, and a significant expenditure of money to perform analysis and retain load as a result of the Proposed Amendments to Chapter 14, Promotional

Practices, and Proposed Rules Chapter 22, Electric Utility Resource Planning. These gas utilities have indicated that it is not presently possible to quantify these effects because it is not known at this time what programs the electric utilities would pursue under the Proposed Amendments to Chapter 14 and the Proposed Rules Chapter 22.

NOTICE OF PUBLIC HEARING: Anyone may submit a statement in support of or in opposition to these Proposed Rules by filing an original and fourteen (14) copies by 5:00 p.m., August 3, 1992 with the Missouri Public Service Commission, Brent Stewart, Executive Secretary, P.O. Box 360, Jefferson City, MO 65102, (314) 751-3234. All comments should bear reference to Case No. EX-92-299, and identify who will answer any questions of the commissioners and the hearing examiner at the public hearing relating to the statement or comments. Anyone may submit a statement in reply to any of these initial comments by filing an original and fourteen (14) copies by 5:00 p.m., August 31, 1992 with the commission, Brent Stewart, Executive Secretary, Case No. EX-92-299. A public hearing has been scheduled to commence at 9:00 a.m., on September 10, 1992 in Hearing Room 520B, Truman State Office Building, 301 West High Street, Jefferson City, MO 65101 and to continue, as and if necessary, through September 11, 1992. The sole purpose of this public hearing is for the commissioners and hearing examiner to ask any questions they may have respecting the initial and reply comments previously filed with the commission. No additional comments or statements in support of or in opposition to these proposed rules will be permitted at the public hearing, nor will cross-examination be permitted.