4 CSR 240-22.010 Policy Objectives

PURPOSE: This rule states the public policy goal that this chapter 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 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 compliance with all applicable state and federal energy and environmental policies, and in a manner that serves the public interest. From time to time, the legislature and citizens of Missouri may pass initiatives that redefine the manner in which the public interest is served by demand-side resources, renewable energy and other electric energy resources. The fundamental objective requires that the utility shall:

(A) Consider and analyze demand-side resources, renewable energy and traditional supply-side resources on an equivalent basis, subject to compliance with applicable state and federal legal mandates that may affect the selection of utility electric energy resources, in the resource planning process;

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

(C) Explicitly identify and, where possible, quantitatively analyze any other 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 developing the resource acquisition strategy. These considerations shall include, but are not necessarily limited to, mitigation of:

1. Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans;
2. Risks associated with new or more stringent energy and/or environmental legal mandates or regulations that may be imposed at some point within the planning horizon; and
3. Rate increases associated with alternative resource plans.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993.
*Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)

4 CSR 240-22.020 Definitions

PURPOSE: This rule defines terms used in the rules comprising 4 CSR 240-22--Electric Utility Resource Planning.
PUBLISHER'S NOTE: The publication of the full text of the material that the adopting agency has incorporated by reference in this rule would be unduly cumbersome or expensive. Therefore, the full text of that material will be made available to any interested person at both the Office of the Secretary of State and the office of the adopting agency, pursuant to section 536.031.4, RSMo. Such material will be provided at the cost established by state law.

(1) Avoided cost means the cost savings obtained by substituting demand-side resources for existing and new supply resources.

(2) Candidate resource options are demand-side resources that pass the screening test 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) Annual update filing means the annual update report prepared by the utility in advance of the annual update workshop and the summary report prepared by the utility following the workshop as referenced in 4 CSR 240-22.080(3).

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

(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) Concern means anything that, while not rising to a deficiency, may prevent the electric utility’s resource acquisition strategy from effectively fulfilling the objectives of 4 CSR 240-22.010(2)(A)—(C).

(7) 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.

(8)Deficiency means anything that would cause the electric utility’s resource acquisition strategy to fail to meet the requirements identified in 4 CSR 240-22.010(2)(A)—(C).

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

(10) Demand-side 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.

(11) Demand-side rate means a rate structure for retail electric service designed to reduce the net consumption or modify the time of consumption of a customer rate class.

(12) Demand-side resource is a demand-side program or a demand-side rate conducted by the utility to modify the net consumption of electricity on the retail customer's side of the meter. A load building program or rate is not a demand-side resource.

(13) Electric utility or utility means any electrical corporation as defined in section 386.020, RSMo 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 generated or used over a specified interval of time measured in kilowatt-hours (kWh).

(17) Energy-efficiency measure means any device, technology 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 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) 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 probabilities. The utility shall 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) Implementation period means the time interval between the triennial compliance filings required of each utility pursuant to 4 CSR 240-22.080.

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

(23) 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.

(24) Legal mandates include state or federal legislation, rules, ordinances, codes, executive orders, regulatory orders, court decisions and any other government mandate affecting the electric utility loads, resources or resource plans.

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

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

(27) 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.

(28) 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.

(29) 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.

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

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

(32) 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.

(33) Major class is a cost of service class of the utility.

(34) 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.

(35) 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.

(36) Nominal dollars mean future or then-current dollar values that are not adjusted to remove the effects of anticipated inflation.

(37) 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.

(38) 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.

(39) 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.

(40) Probable environmental cost means the expected cost to the utility of complying with new or additional environmental legal mandates, regulations, taxes or other requirements that utility decision-makers judge may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.

(41) Realistic achievable potential of a demand-side candidate resource option or portfolio is an estimate of the load impact that would occur if that resource option or portfolio were implemented in amounts consistent with the most aggressive cost-effective implementation of the resource option or portfolio considered by the utility.

(42) 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.

(43) 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.

(44) 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.

(45) RTO means Regional Transmission Organization.

(46) Special contemporary issues means a written list of issues prepared by commission staff with input from intervenors that are evolving new issues, which may not otherwise have been addressed by the utility or continuations of unresolved issues from the preceding full compliance filing or annual update filing. Each utility shall evaluate and incorporate special contemporary issues in its next full compliance filing or annual update filing.

(47) Stakeholder group means:
(A) Staff, public counsel, and any person or entity granted intervention in a prior Chapter 22 proceeding of the electric utility. Such persons or entities shall be a party to any subsequent related Chapter 22 proceeding of

the electric utility without the necessity of applying to the commission for intervention; and

(B) Any person or entity granted intervention in a current Chapter 22 proceeding of the electric utility.

(48) Subjective probability means the judgmental likelihood that the outcome will actually occur.

(49) 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.

(50) Technical potential of a demand-side candidate resource option or portfolio is an estimate of the load impact that would occur if that resource option or portfolio were implemented at every location in the utility's service territory where the resource option or portfolio is technically feasible but has not yet been implemented. Since each demand-side candidate resource option or portfolio is cost-effective under the total resource cost test, the technical potential is the load impact that would occur if the cost-effective resource option or portfolio were implemented everywhere it is feasible. It is the same as the maximum economic potential of the demand-side resource option or portfolio.

(51) Total resource cost test is a test of the cost-effectiveness of demand-side programs or demand-side tariffs that compares the sum of avoided utility costs plus avoided probable environmental costs to the sum of all incremental costs related to the end-use measures that are implemented due to the program or related to the tariffs (including both utility and participant contributions), plus utility costs to administer, deliver and evaluate each demand-side program or demand-side tariff to quantify the net savings obtained by substituting the demand-side program or demand-side tariff for supply resources.

(52) 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.

(53) 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.

(54) The utility cost test is a test of the cost-effectiveness of demand-side programs or demand-side tariffs that compares the avoided utility costs to the sum of all utility incentive payments, plus utility costs to administer, deliver and evaluate each demand-side program or demand-side tariff to quantify the net savings obtained by substituting the demand-side program or demand-side tariff for supply resources.

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

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

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993. *Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)

4 CSR 240-22.030 Load Analysis and Load Forecasting

PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing loads, and the purposes to be accomplished by load analysis and by load forecast models. The load analysis discussed in this rule is intended to support both demand-side management efforts of 4 CSR 240-22.050 and the load forecast models of 4 CSR 240-22.030. This rule also sets the minimum standards for the documentation of the inputs, components and methods used to derive the load forecasts.

(1) Selecting Load Analysis Methods. The utility may choose multiple methods of load analysis if it deems doing so is necessary to achieve all of the purposes of load analysis and if the methods are consistent with, and calibrated to, one another. The utility shall document its intended purposes for load analysis methods, why the selected load analysis methods best fulfill those purposes, and how the load analysis methods are consistent with one another and with the end-use consumption data used in the demand-side analysis as described in 4 CSR 240-22.050. As a minimum, the load analysis methods shall be selected to achieve the following purposes:

(A) To identify end-use measures that may be potential demand-side resources, generally, those end-use measures with an opportunity for energy and/or demand savings;

(B) To derive a data set of historical values from load research that can be used as dependent and independent variables in the load forecasts;

(C) To analyze of impacts of implemented demand-side programs and demand-side rates on the load forecasts and to assess the effectiveness of demand-side resources. This information may be used in the development of evaluation plans required by 4 CSR 240-22.070(8), or in the evaluation of the performance of the demand-side programs or rates after they are implemented; and

(D) To preserve, in a historical data base, the results of the load analysis used to perform the demand-side analysis as described in 4 CSR 240-22.050, and the load forecasting described in 4 CSR 240-22.030.

(2) Historical Data Base for Load Analysis. 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. As a minimum, the historical data base shall be maintained for each of the major classes;

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

1. For each jurisdiction for which it prepares customer and energy and demand forecasts, for each major class, the actual monthly energy usage and number of customers and weather-normalized monthly energy usage;

2. For each jurisdiction and major class, estimated actual and weather-normalized demands at the time of monthly system 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 per unit component, for both actual and weather-normalized loads.

1. The number of units component shall be the number of customers, square feet, devices, or other units as appropriate to the customer class and the load analysis method selected by the utility. The utility shall select the units component with the intent of providing meaningful load analysis for

demand-side analysis and maintaining the integrity of the data base over time.

2. The utility shall develop and implement a procedure to routinely measure and regularly update estimates of the effect of departures from normal weather on class and system electric loads. The estimates of the effect of weather on historical major class and system loads shall incorporate the nonlinear response of loads to daily weather and seasonal variations in loads.

3. 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 relevant statistical results of the models, including parameter estimates and tests of statistical significance; and

(D) Length of Historical 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.

(3) Analysis of Number of Units. For each major class, the utility shall analyze the historical relationship between the number of units and the economic or demographic factors (explanatory variables) that affect the number of units for that major class. The analysis may incorporate or substitute the results of secondary analyses, with the proviso that the utility analyze, document and verify the applicability of those results to its service territory. If the utility develops primary analyses, or to the extent they are available from secondary analyses, these relationships shall be specified as statistical or mathematical models that relate the number of units to the explanatory variables.

(A) Choice of explanatory variables. The utility shall identify appropriate explanatory variables as predictors of the number of units for each major class. The critical assumptions that influence the explanatory variables shall also be identified and documented.

(B) Documentation of statistical models shall include the elements specified in section (2)(C)of this rule. Documentation of mathematical models shall include a specification of the functional form of the equations if the utility develops primary analyses, or to the extent they are available if the utility incorporates secondary analyses.

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

(A) End-Use Load Detail. For each major class, use per unit shall be disaggregated, where information permits, by end-uses that contribute significantly to energy use or peak demand.

1. The utility shall consider developing information on at least the following end-use loads;

A. For the residential sector, on lighting, space cooling, space heating, water heating, refrigerators, freezers, cooking, clothes washers, clothes dryers, television, personal computers, furnace fans, and other uses.

B. For the commercial sector, on space heat, cooling, ventilation, water heat, refrigeration, lighting, office equipment, and other uses;

C. For the industrial sector, on machine drives, HVAC, lighting, process heating, and other uses.

2. The utility may modify the end-use loads specified in section (4)(A)1.

A. The utility may remove or consolidate the specified end-use loads if it determines that a specified end-use load is not contributing, and is not likely to contribute in the future, significantly to energy use or peak demand in a major class.

B. The utility shall add to the specified end-use loads if it determines that an end-use load currently not specified is likely to contribute significantly to energy use or peak demand in a major class.

C. The utility shall provide documentation of its decision to modify the specified end-use loads for which information is developed, as well as an assessment of how the modifications can be made to best preserve the continuity and integrity of the end-use load data base.

3. For each major class and each end–use load, including those listed in section (4)(A)1., if information is not available, the utility shall provide a schedule for acquiring this end-use load 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 load information has proven to be infeasible.

4. 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.

(B) The data base and historical analysis required for each end use shall be developed from utility-specific survey or primary data. The data base and analysis may incorporate or substitute the results of secondary data, with the proviso that the utility analyze, document and verify the applicability of those results to its service territory. 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 load, identified in section (4)(A), the utility shall implement a procedure to develop and maintain adequate 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 the data before each scheduled filing pursuant to 4 CSR 240-22.080; and

2. Estimates of end-use energy and demand. For the end-use loads identified in section (4)(A), the utility shall estimate monthly 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.

(5) Selecting Load Forecasting Models. The utility shall select load forecast models and develop the historical data base needed to support those models. The selected load forecast models will include a method of end-use load analysis for at least the residential and small commercial class, unless the utility demonstrates that end-use load methods are not practicable and provides documentation that other methods are superior. The utility may choose multiple models and methods if it deems doing so is necessary to achieve all of the purposes of load forecasting and if the methods and models are consistent with, and calibrated to, one another. The utility shall document its intended purposes for load forecast models, why the selected load forecast models best fulfill those purposes, and how the load forecast models are consistent with one another and with the end-use usage data used in the demand-side analysis as described in 4 CSR 240-22.050. As a minimum, the load forecast models shall be selected to achieve the following purposes:

(A) Assessment of consumption drivers and customer usage patterns: to better understand customer preferences and their impacts on future electricity energy and demand requirements, including weather sensitivity of load;

(B) Long term load forecasts: to serve as a basis for planning capacity and energy service needs. This can be served by any forecasting method or methods that produce reasonable projections (based on comparing model projections of loads to actual loads) of future demand and energy loads;

(C) Policy analysis: to assess the impact of legal mandates, economic policy and rate policy on future electricity energy and demand requirements. The utility shall use forecast models based on end-use loads for the analysis of actual or proposed legal mandates and forecast models including appropriate econometric parameters for the analysis of economic and rate policies. The utility may substitute other types of load forecast models if it demonstrates that the substitute load forecast models can adequately analyze the impacts of legal mandates, economic policies and rate policies;

(6) Load Forecasting Model Specifications.

(A) For each load forecasting model selected by the utility pursuant to section 4 CSR 240-22.030(5), the utility shall:

1. Identify appropriate independent variables as predictors of energy and peak demand for each major class. The critical assumptions that influence the independent variables shall also be identified.

A. The utility shall assess the applicability of the historical explanatory variables pursuant to section (3)(A) to its selected forecast model;

B. To the extent that the independent variables selected by the utility differ from the historical explanatory variables, the utility shall explain and document those differences.

2. Develop and document any mathematical or statistical equations comprising the load forecast models, including a specification of the functional form of the equations.

3. Assess the applicability of any load forecast models or portions of models that were utilized by the utility but developed by others, including a specification of the functional forms of any equations or models, to the extent they are available.

(B) If the utility selects load forecast models that include end-use load methods, the utility shall explain and document any deviations in the independent variables or functional forms of the equations from those derived from load analysis in sections (3) and (4).

(C) Historical Data Base for Load Forecasting. In addition to the load analysis data base, the utility shall develop and maintain a data base consistent with and as needed to run each forecast model utilized by the utility. As a minimum, the utility shall:

1. Develop and maintain a data set of historical values for each independent variable of each forecast model. The historical values for each independent variable shall be collected for a period of ten (10) years, or such period deemed sufficient to allow the independent variables to be accurately forecasted over the entire planning horizon.

2. Archive previous projections of all independent variables used in the energy usage and peak load forecasts made in at least the past ten (10) years and provide a comparison of the historical projected values in prior plan filings to actual historical values and to projected values in the current compliance filing.

3. Archive all previous forecasts of energy and peak demand, including the final data sets used to develop the forecasts, made in at least the past ten (10) years. Provide a comparison of the historical final forecasts to the actual historical energy and peak demands, and to the current forecasts in the current triennial compliance filing. The utility shall use the historical forecast information in its assessment of energy consumption trends and the ability of forecasting methods to produce reasonable

projections of future demand and energy loads pursuant to 4 CSR 240-22.030 (5).

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

(A) Major 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 components.

1. The utility shall document how the base case forecasts of energy usage and demands have 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. If the methodology does not incorporate economic and demographic factors, the utility shall document how it accounted for the effects of these factors.

2. The utility shall document how the forecasts of energy usage and demands have taken into account the effects of legal mandates affecting the consumption of electricity, such as but not limited to federal, state and local appliance efficiency standards or building codes.

3. The utility shall document how the forecasts of energy usage and demands are consistent with trends in historical consumption patterns, end uses and end-use efficiency in the utility’s service area as identified pursuant to sections 4 CSR 240-22.030(2), (3) and (4).

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

5. Where judgment has been applied to modify the results of its energy and peak forecast models, the utility shall specify the factors which caused the modification and shall explain how those factors were quantified.

(B) Forecasts of independent variables. The forecasts of independent variables shall be specified and clearly documented.

1. Documentation of mathematical models developed by the utility to forecast the independent variables shall include the reasons the utility selected the models as well as specification of the functional form of the equations.

2. If the utility adopted forecasts of independent variables developed by another entity, documentation shall include the reasons the utility selected those forecasts, an analysis showing those forecasts are applicable to the utility’s service territory, and if available a specification of the functional form of the equations.

3. These forecasts of independent variables shall be compared to historical trends in those variables and significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

4. Where judgment 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.

(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 peak demands at time of summer and winter system peaks for the major rate classes.

(8) Load Forecast Sensitivity Analysis. The utility shall analyze the sensitivity of the dependent variables of the base-case forecast for each major class to variations in the independent variables identified in section 4 CSR 240-22.030(6)(A).

(A) The utility shall produce at least two (2) additional normal weather 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 240-22.060.

(B) The utility shall estimate the sensitivity of system peak load forecasts to extreme weather conditions. This information will be used by utility decision makers to assess the ability of alternative resource plans to serve load under extreme weather conditions when selecting the preferred resource plan pursuant to 4 CSR 240-22.070(1).

(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 prepare a report that contains at least the following information:

(A) Identification of the load forecast models selected by the utility pursuant to section (5).

1. The narrative will describe the forecast models selected to fulfill each of the functions in sections (5) (A)-(C), explain why they were selected, and how the utility maintains consistency between the models. For example, if an end-use load model was selected to analyze the impacts of legal mandates for energy efficiency, but an econometric model was selected to develop the long term forecast, the utility shall explain what it did to assure that the end-use and econometric models used consistent inputs and generated consistent results.

2. The utility shall provide, describe and document the mathematical or statistical relationships between the independent variables and the forecasts of energy and peak loads pursuant to (6)(A), including any assumptions made that influence those relationships.

3. The narrative will describe the how the forecast models selected address the economic, demographic and legal factors specified in (7)(A).

4. The narrative will also identify and describe the independent variables utilized in the load forecast models pursuant to sections (6)(A) and (6)(B). The utility shall provide, describe and document mathematical or statistical relationships used to forecast the independent variables pursuant to (7)((B), and the assumptions influencing these independent variables.

(B) The utility shall describe its load analysis pursuant to sections (2), (3) and (4). The narrative shall describe and document the analysis of the trends in the number of units, including the identification and selection of explanatory variables as required in section (3). The narrative shall also describe and document the analysis of energy use per unit as required in section (4).

(C) For each major class specified pursuant to section (2)(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 energy usage per unit and total class energy usage for the base-case forecast, and where available, the energy usage per unit by end-use load.

C. The utility shall provide a narrative discussion that identifies, analyzes and explains significant differences between the forecast energy use per unit and the long-term and recent trends.

(D) The utility shall describe any adjustments that it made to historical data prior to using it in its development of the forecasting models.

(E) For each major class specified pursuant to section (2)(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 coincident demands per unit and total class coincident demands for the base-case forecast, and where available, the coincident demands by end-use load.

(F) For the forecast of class energy and peak demands, the utility shall provide a summary of the sensitivity analysis required by section (8) of this rule that shows how changes in the independent variables affect the forecast. The utility shall identify and describe independent variables, describe how and why they were determined to be key independent variables, provide and document the expected range of values for the key independent variables and show how changes in the independent variables affect the forecast. The utility shall provide plots comparing the system peak demand assuming normal weather and extreme weather.

(G) 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. All plots will be labeled as stand alone figures, axes will be labeled with units and the plot will be referenced and explained in the text.

5. The utility shall describe in a narrative how the subjective probabilities assigned to each base, low and high forecast were determined.

6. The utility shall describe any adjustments that it made to historical data prior to using it in its development of the forecasting models

(H) 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 load 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.

(I) For the net system load profiles, the utility shall provide plots for the summer peak day and the winter peak day.

1. The plots shall show each of the major class components of the net system load profile in a cumulative manner.

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

3. All plots will be labeled as stand alone figures, axes will be labeled with units and the plot will be referenced and explained in the text.

(J) The data presented in all plots also shall be provided in tabular form. Data tables will be labeled including an identification of the corresponding plot, numbered, and identified and explained in the text.

(K) The utility shall provide a description of the methods used to develop all forecasts required by this rule, including an annotated summary that shows how these methods comply with the specific provisions of this rule. If end-use load methods have not been used in forecasting, an explanation as to why they have not been used shall be included. Also included shall be the utility's schedule to acquire end-use load information and to develop end-use load forecasting techniques or a discussion as to why the acquisition of end-use load information and the development of end-use load forecasting techniques are either impractical or not cost-effective.

(L) The utility shall provide a summary of its archived historical forecasts. The summary shall include:

1. A comparison of the historical final forecasts filed in triennial compliance filings over the preceding ten (10) years to the current forecasts and actual loads;
2. A narrative discussion of consumption trends identified in the forecasts
3. A narrative discussion of the ability of various forecasting models considered by the utility to produce reasonable projections.

(M) The utility shall provide a description of its procedure to measure and update the affects of weather sensitivity on class and system electric loads, and shall document the methods used as required by section (2) (C) 2. and 3.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993. *Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)

4 CSR 240-22.040 Supply-Side Resource Analysis

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in supply-side resource analysis.

(1) The utility shall identify a variety of potential supply-side resource options which the utility can reasonably expect to develop and implement solely through its own resources or for which it will be a major participant. These options include new plants using existing generation technologies; new plants using new generation technologies, including technologies expected to become commercially available within the twenty (20) year planning horizon; utility renewable energy resources, including a wide variety of renewable generation technologies; technologies for distributed generation; 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 sufficient to fairly analyze and compare each of these potential resource options, including at least those attributes needed to assess capital cost, fixed and variable operation and maintenance costs, and probable environmental costs.

(2) The utility shall analyze each supply-side resource option referred to in section (1). The utility may conduct a a preliminary screening analysis to determine a short list of candidate resource options, or it may consider all of the supply-side resource options to be preliminary supply-side candidate resource options pursuant to section (2)(C). The purpose of the preliminary screening analysis 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. All costs shall be expressed in nominal dollars.

(A) Cost rankings shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the resource using the utility discount rate. In lieu of levelized cost, the utility may use an economic carrying charge annualization in which the annual dollar amount increases each year at an assumed inflation rate and for which a stream of these amounts over the life of the resource yields the same present value.

(B) The probable environmental costs of each supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental legal mandates or regulations that may be imposed at some point within the planning horizon. The utility shall specify at least two (2) levels of mitigation that are more stringent than existing requirements which are judged to have a nonzero probability of being imposed at some point within the planning horizon. If the utility determines that only one level of mitigation is possible, the utility shall explain why only one level of mitigation is possible and provide justification for the selected level. The utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that additional legal mandates or regulations requiring that level of mitigation will be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation level for each identified pollutant.

(C) The utility shall indicate which supply-side options it considers to be preliminary supply-side candidate resource options for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). Any utility using the preliminary screening analysis to identify preliminary supply-side candidate resource options 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 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 the interconnection and any other transmission requirements associated with the preliminary supply-side candidate resource options.

(A) The analysis shall include the identification of transmission constraints, as estimated pursuant to 4 CSR 240-22.045 (3), whether within the RTO's footprint, on an interconnected RTO, or a transmission system that is not part of a RTO. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the supply-side candidate resource options under consideration, that the costs of transmission system investments associated with supply-side resources as estimated pursuant to 4 CSR 240-22.045(3) are properly considered and to provide an adequate foundation of basic information for decisions about the following types of supply-side resource alternatives:

1. Joint participation in generation construction projects;
2. Construction of wholly-owned generation facilities;
3. Participation in major refurbishment, life extension, upgrading or retrofitting of existing generation facilities;
4. Improvements on its transmission and distribution system to increase efficiency and reduce power losses;
5. Acquisition of existing generating facilities; and
6. Opportunities for new long-term power purchases and sales, and short-term power purchases that may be required for bridging the gap between other supply options, both firm and nonfirm, that are likely to be available over all or part of the planning horizon.

(B) The utility shall indicate which of the preliminary supply side candidate resource options, if any, are eliminated from further consideration on the basis of the interconnection and other transmission analysis and shall explain the reasons for their elimination.

(C) The utility shall include the cost of interconnection and any other transmission requirements, in addition to the utility resource and probable environmental costs, in the cost of supply-side candidate resource options advanced for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3).

(D) The supply-side candidate resource options that the utility passes on for further evaluation in the integration process shall represent a wide variety of supply-side resource options with diverse fuel and generation technologies, including a wide range of renewable technologies and technologies suitable for distributed generation.

(4) 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-side candidate resource options. 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, as applicable to the supply-side candidate resource option:

(A) Fuel price forecasts, including fuel delivery costs, 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;

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

(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;

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

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

(F) Estimated costs of interconnection or other transmission requirements associated with each supply-side candidate resource option.

(5) 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-side resource identified pursuant to section (1) and the utility cost and the probable environmental cost for each resource option and an assessment of whether each supply-side resource qualifies as a utility renewable energy resource;

(B) Identification of preliminary supply–side candidate resource options and an explanation of the reasons why each rejected supply-side resource option was not included as a preliminary supply-side candidate resource option;

(C) A summary of the interconnection and other transmission requirements associated with each preliminary supply-side candidate resource option pursuant to section (3), including the cost of those transmission requirements;

(D) A list of the supply-side candidate resource options for which the forecasts, estimates and probability distributions described in section (4) have been developed or are scheduled to be developed;

(E) A summary of the results of the uncertainty analysis described in section (4) that has been completed for supply-side candidate resource options; and

(F) A summary of the mitigation cost estimates developed by the utility for the supply-side candidate resource options identified pursuant to section (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;

(G) A narrative describing the utility’s process for identifying and analyzing supply-side resource options and documenting the utility’s choice of supply-side candidate resource options to advance to the integration analysis.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993. *Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)

4 CSR 240-22.045 Transmission and Distribution Analysis

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting.

(1) The electric utility shall consider the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objectives set out in 4 CSR 240-22.010. Each utility shall consider at least those improvements to the transmission and distribution networks required to:

(A) Reduce transmission power and energy losses. Opportunities to reduce transmission network losses are among the supply-side resources evaluated pursuant to 4 CSR 240-22.040 (3). 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 network loss-reduction measures.

(B) Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options.

(C) Facilitate power purchases or sales. The utility shall assess the transmission upgrades needed to purchase or sell pursuant to 4 CSR 240-22.040 (3). An estimate of the portion of costs of these upgrades that are allocated to the utility shall be reflected in the analysis of resource options.

(D) Incorporate advanced transmission and distribution network technologies that may become available during the planning horizon. The utility shall assess transmission and distribution improvements that facilitate or expand the availability and cost effectiveness of demand-side or supply-side resources. The costs and capabilities of these advanced transmission and distribution technologies shall be reflected in the cost benefit analyses of the resource options.

(2) Avoided transmission and distribution cost. The utility shall develop an avoided transmission capacity cost and an avoided distribution capacity cost to include in the avoided demand cost pursuant to 4 CSR 240-22.050(4)(A).

(3) Transmission analysis. The utility and the Regional Transmission Organization (RTO) it belongs to both participate in the process for planning transmission upgrades. Each year, the RTO develops long-term transmission expansion plans designed to meet North American Electric Reliability Corporation (NERC) reliability standards. The RTO transmission expansion plans include upgrades for the purposes of interconnecting generation, improving reliability and improving economics.

(A) The utility shall actively participate in the development of the RTO transmission plan, and shall review the RTO transmission expansion plans each year to assess whether the RTO transmission expansion plans, in the judgment of the utility decision makers, are in the interests of the utility’s customers.

(B) The utility may use the RTO transmission expansion plan and where necessary shall develop supplemental information:

1. To develop information regarding the cost and timing of transmission upgrades to reduce losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;
2. To identify transmission upgrades to incorporate advanced technologies;
3. To estimate avoided transmission costs;

4. To estimate the portion and amount of incremental costs of regional transmission upgrades that would be allocated to the utility; and

5. To estimate any revenue credits the utility will receive in the future for previously built or planned regional transmission upgrades; and

6. To estimate timing of needed transmission and distribution resources and any transmission resources being built by the RTO for economic reasons that may impact the alternative resource plans of the utility.

(C) The utility shall provide copies of the RTO expansion plan, its assessment of the plan and any supplemental information developed by the utility to fulfill the requirements in section (3)(B) of this rule.

(4) Analysis required for transmission and distribution network investments to incorporate advanced technologies.

(A) The utility shall augment the RTO plans for transmission upgrades to incorporate advanced transmission technologies as necessary to optimize the investment in the advanced technologies for transmission facilities owned by the utility.

(B) The utility shall develop plans for distribution network upgrades as necessary to optimize its investment in advanced distribution technologies.

(C) The utility shall optimize investment in advanced transmission and distribution technologies based on an analysis of:

1. Total costs, including:

a. Costs of the advanced grid investments;

b. Costs of the non-advanced grid investments;

c. Reduced resource costs, especially through enhanced demand response resources and enhanced integration of customer owned generation resources; and

d. Reduced production costs;

2. Cost effectiveness, including:

a. The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;

b. The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies; and

c. Additional non-monetary factors considered by the utility;

3. Societal benefit, including:

a. More consumer power choices;

b. Improved utilization of existing resources;

c. Opportunity to minimize cost in response to price signals;

d. Opportunity to minimize environmental impact in response to environmental signals;

4. Any other factors identified by the utility; and

5. Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080 (4) or the stakeholder group process pursuant to 4 CSR 240-22.080 (5).

(E) Before investing in non-advanced transmission and distribution grid technologies the utility shall:

1. Conduct an analysis which demonstrates that investment in each non-advanced transmission and distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies;

2. Document the analysis;

3. Document its decision to invest in non-advanced transmission or distribution grid technologies; and

4. Include investment in non-advanced transmission and distribution grid technologies in its resource acquisition strategy pursuant to 4 CSR 240-22.070 (7).

(5) 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) Copy of the most recent RTO long-term transmission expansion plan including the utility's summary of the portions of RTO plan relevant to the utility's resource planning;

(B) A report documenting the utility's assessment of the applicability of the RTO's long-term transmission expansion plan to each of the requirements of section (3), including documentation of the analysis and conclusions;

(C) A report documenting the supplemental information developed by the utility to satisfy the requirements of section (3), including documentation of the analysis and conclusions;

(D) A report for consideration in 4 CSR 240-22.040(3)that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable transmission network, including:

1. A list of the transmission upgrades needed to physically interconnect a generation source within the RTO footprint;

2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the RTO including: a) required for firm transmission service from the point of delivery to the utility's load; and b)required for financial transmission rights from a point of delivery within the RTO to the utility's load;

3. A list of transmission upgrades needed to physically interconnect a generation source located outside the RTO footprint;

4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the RTO including: a) required for firm transmission service to a point of delivery within the RTO footprint; and b)required for financial transmission rights to a point of delivery within the RTO footprint;

5. The estimated total cost of each transmission upgrade and estimated congestion costs;

6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the utility.

(E) A report that documents the utility's plans to upgrade transmission and distribution networks to incorporate advanced grid technologies. The report shall include:

1. Documentation of the analysis and utility's conclusions regarding the utility's investments in transmission and distribution advanced grid technologies;

2. A description the utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks;

3. A description of the impact of the implementation of distribution advanced grid technologies on the selection of a resource acquisition strategy; and

4. A description of the impact of the implementation of transmission advanced grid technologies on the selection of a resource acquisition strategy.

(F)If the utility plans to implement non-advanced technologies instead of advanced grid technologies, the report shall document the analysis that demonstrates that non-advanced grid technologies are more appropriate and beneficial to consumers.

(G) A report that presents and documents the utility’s calculation of avoided transmission costs and avoided distribution costs.

AUTHORITY: (Add authorities)

4 CSR 240-22.050 Demand-Side Resource Analysis

PURPOSE: This rule specifies the principles by which potential demand-side resources shall be developed and analyzed for cost-effectiveness. It also requires the selection of demand-side candidate resource options that are passed on to integrated resource analysis in 4 CSR 240-22.060 and an assessment of their technical potentials and realistic achievable potentials.

(1) The utility shall identify a set of potential demand-side resources from which demand-side candidate resource options will be identified for the purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). A potential demand-side resource consists of a demand-side program designed to deliver one or more energy efficiency and energy management measures or a demand-side rate. The utility shall design the set of potential demand-side resources:

(A) To provide broad coverage of:

1. Appropriate customer market segments within each major class;

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

3. All major end uses, including at least lighting, refrigeration, space cooling, space heating, water heating and motive power; and

4. Renewable energy sources, distributed generation resources and energy technologies that substitute for electricity at the point of use;

(B) To include demand-side resources with the goal of achieving all cost-effective demand-side savings. To accomplish this goal, the utility shall design highly effective potential demand-side programs pursuant to section (A) that broadly cover the full spectrum of cost-effective end-use measures for all customer market segments pursuant to section (1)(A)1;

(C) To include demand-side rates for all customer market segments pursuant to section (1)(A)1;

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

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

1. Reduce or manage energy use; or

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

(2) The utility shall conduct market research studies, customer surveys, pilot demand-side programs, pilot demand-side rates, test marketing programs and other activities as necessary to estimate the technical potential and realistic achievable potential of potential demand-side resources for the utility and to develop the information necessary to design and implement cost-effective demand-side programs and demand-side rates. These research activities shall be designed to provide a solid foundation of information applicable to the utility about how and by whom energy-related decisions are made and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency and energy management impacts. The utility may compile existing data or adopt data developed by other entities, including government agencies and other utilities, as long as the utility verifies the applicability of the adopted data to its service territory.

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

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

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

(C) Assemble menus of end-use measures that are appropriate to the shared characteristics of each market segment, including the role of technological changes in end-uses that may be reasonably anticipated to occur during the planning horizon;

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

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

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

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

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

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

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

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

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

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

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

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

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

F. Other costs identified by the utility.

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

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

(A) Review demand-side rates that have been implemented by other utilities with similar electric prices and customer makeup to determine if similar rates would be applicable for the utility;

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

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

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

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

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

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

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

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

A. The cost of incentives to customers to participate in the potential demand-side rate paid by the utility. The utility shall consider multiple levels of incentives to achieve customer participation in each potential demand-side rate, with commensurate adjustments to the technical potential and the realistic achievable potentials of that potential demand-side rate;

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

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

D. Other costs identified by the utility.

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

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

(A) In each year of the planning horizon, the benefits of each potential demand-side program and each potential demand-side rate shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost. These calculations shall be performed using the avoided probable environmental costs.

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

demand cost, and the capacity cost chosen shall be consistent throughout the triennial compliance filing.

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

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

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

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

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

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

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

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

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

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

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

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

(A) The utility may bundle demand-side candidate resource options into portfolios, as long as the requirements pursuant to section (1) are met and as long as multiple demand-side candidate resource options and portfolios advance for consideration in the integrated resource analysis in 4 CSR 240-22.060.

(B) For each demand-side candidate resource option or portfolio, 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.

(C) The utility shall assess the potential uncertainty associated with the demand-side candidate resource options or portfolios by estimating the technical potential and realistic achievable potential of each demand-side candidate resource option or portfolio.

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

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

(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 prepare a report that contains at least the following information:

(A) A list of potential demand-side programs developed pursuant to the requirements of section (3) of this rule;

(B) Documentation of the methods and assumptions used to develop the potential demand-side programs;

(C) A list of potential demand-side rates developed pursuant to the requirements of section (4) of this rule;

(D) Documentation of the methods and assumptions used to develop the potential demand-side rates;

(E) Copies of completed market research studies, pilot programs, pilot rates, test marketing programs and other studies as required by section (2) of this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates;

(F) A description of each market segment identified pursuant to section (3)(B);

(G) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs and program participant costs in each year of the planning horizon for each potential demand-side program developed pursuant to section (3) of this rule and for each potential demand-side rate developed pursuant to section (4) of this rule;

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

(G) Documentation of the methods and assumptions used to develop the avoided costs;

(I) A summary of the time differentiated load impact estimates over the planning horizon for each demand-side candidate resource option pursuant to section (6)(B); and

(J) The results of the assessment of uncertainty of demand-side candidate resource options or portfolios, including an explanation of how the utility determined the technical potential and the realistic achievable potential of those demand-side candidate resource options or portfolios.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993.
*Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)

4 CSR 240-22.060 Integrated Resource Plan and Risk 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. This rule also requires the utility to identify the critical uncertain factors that affect the performance of resource plans and establishes minimum standards for the methods used to assess the risks associated with these uncertainties.

(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 meet.

(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.

(A) These performance measures shall include at least the following:

1. Present worth of utility revenue requirements;
2. Present worth of probable environmental costs;
3. Present worth of out-of-pocket costs to participants in demand-side programs and rates;
4. Levelized annual average rates;
5. Maximum single-year increase in annual average rates;
6. Financial ratios or other credit metrics indicative of the utility’s ability to finance implementing the preferred plan; and
7. Other measures that utility decision-makers believe are appropriate for assessing the performance of resource plans relative to the planning objectives identified in 4 CSR 240-22.010(2).

(B) All present worth and levelization calculations shall use the utility discount rate and all costs and benefits shall be expressed in nominal dollars.

(3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of demand-side and supply-side resources to develop a set of alternative resource plans, each of which is designed to achieve one (1) or more of the planning objectives identified in 4 CSR 240-22.010(2). Demand-side resources are the demand-side candidate resource options and portfolios developed in 4 CSR 240-22.050(5). Supply-side resources are the supply-side candidate resource options developed in 4 CSR 240-22.040(3)(B). The goal is to develop a set of alternative plans based on substantively different mixes of supply-side and demand-side resources to assess their relative performance under expected conditions as well as their robustness under a range of conditions.

(A) The utility shall develop at least one alternative plan, and as many as may be needed to assess the range of resource options, for each of the following cases. Each of the plans shall provide resources to meet all projected load growth and resource retirements over the planning period in a manner specified by the case. The utility shall examine cases that:

1. Minimally comply with the state and federal standards for demand-side resources, renewable energy resources, and other mandated resources. This constitutes the compliance benchmark case for planning purposes;

2. Utilize only renewable energy resources, if that results in more renewable energy resources than the minimally compliant plan. This constitutes the aggressive renewable energy case for planning purposes;
3. Utilize only demand-side resources, if that results in more demand-side resources than the minimally compliant plan. This constitutes the aggressive demand-side resource case for planning purposes;
4. Utilize only other state or federal mandated energy resources, if that results in more mandated energy resources than the minimally compliant plan. For planning purposes, this constitutes the aggressive case for implementing the mandated energy resource;
5. Optimally comply with the state and federal standards for demand-side resources, renewable energy resources, and other targeted resources. This constitutes the optimal compliance case, where every mandate is at least minimally met, but some resources may be optimally utilized at levels greater than the mandated minimums;
6. Any other plan specified by the staff as a special contemporary issue pursuant to 4 CSR 240-22.080(4);
7. Any other plan specified by commission order; and
8. Any additional alternative resource plans that the utility deems should be analyzed.

(B) The alternative resource plans developed at this stage of the analysis shall not include load-building programs, which shall be analyzed as required by 4 CSR 240-22.070(5).

(C) The utility shall include in its development of alternative resource plans the impact of:
1. The potential retirement or life extension of existing generation plants;
2. The addition of equipment on generation plants to meet environmental requirements; and
3. The conclusion of any currently implemented demand-side resources.

(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 on a year-by-year basis in order to assess the annual and cumulative impacts of alternative resource plans.

(A) The analysis of financial impact of alternative resource plans shall provide comparative estimates of at least the prevailing measures of the utility's financial condition for each year of the planning horizon;

(B) The analysis shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law;

(C) The analysis 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) The utility shall 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) and analyze the risks associated with alternative resource plans. This assessment shall explicitly state and document the probabilities that utility decision-makers assign to each of these uncertain factors.

(6) The utility shall identify the uncertain factors that are critical to the performance of the alternative resource plans. The utility shall consider 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 and access to capital;

(C) Future changes in legal mandates, regulations or standards;

(D) Relative real fuel prices;

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities for the utility, for a regional transmission organization and/or other transmission systems;

(F) Construction costs and schedules for new generation and generation-related transmission facilities for the utility, for a regional transmission organization and/or other transmission systems;

(G) Purchased power availability, terms, cost, optionality and other benefits;

(H) Price of emission allowances, including at a minimum sulfur dioxide, carbon dioxide and nitrogen oxides;

(I) Fixed operation and maintenance costs for new and 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 rates;

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

(M) Any other uncertain factors that the utility determines may be critical to the performance of alternative resource plans.

(7) The utility decision-makers shall assign a probability pursuant to section (5) of this rule to each uncertain factor deemed critical by the utility. The utility shall compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2). 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.

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

(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 along with a table containing the data used to create the plot:

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 and rate, of the capacity provided by demand-side resources;

3. The composition, by supply-side resource, of the capacity (including reserve margin) provided by supply-side 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 and rate, of the annual energy provided by demand-side resources;

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

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

8. Annual average rates;

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

10. Annual probable environmental costs; and

11. Public and highly confidential forms of the capacity balance spreadsheets completed in the specified format.

(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 discussion of the incremental costs of implementing more renewable energy resources than required to comply with any applicable renewable energy mandates;

(F) A discussion of the incremental costs of implementing more energy efficiency resources than required to comply with any applicable energy efficiency mandates;

(G) A discussion of the incremental costs of implementing more energy resources than required to comply with any other applicable energy resource mandates;

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

(I) A discussion and documentation of the method the utility used to determine the cumulative probability distributions pursuant to 4 CSR 240-22.060(7).

1. 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 probabilities for each outcome were derived;

2. Documentation and analyses supporting the utility’s choice of ranges and probabilities for the uncertain factors;

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

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

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

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993. *Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)

4 CSR 240-22.070 Strategy Selection and Implementation

PURPOSE: This rule requires the utility to select a preferred resource plan, develop an implementation plan and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans, and evaluate demand-side resources.

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

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

(B) Invest only in advanced transmission and distribution technologies unless in the judgment of the utility decision makers, investing in those technologies to upgrade transmission and/or distribution networks is not in the public interest;

(C) Utilize demand-side resources to the maximum amount that in the judgment of the utility decision makers is consistent with the public interest and achieves state energy policies; and

(D) In the judgment of the utility decision-makers, the preferred plan, in conjunction with the deployment of emergency demand response measures and access to short term and emergency power supplies, has sufficient resources to serve load under extreme weather forecasts pursuant to 4 CSR 240-22.030(8)(B).

(2) The utility shall specify 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 explain how these limits were determined. The utility shall also assess whether and under what circumstances other uncertain factors associated with the preferred plan exist that could significantly affect the performance of the preferred plan relative to alternative plans.

(3) 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.

(4) The utility shall develop and document contingent resource plans in the event that the preferred plan should cease to be appropriate, whether due to the limits identified pursuant to 4 CSR 240-22.070(2) being exceeded or for any other reason.

(A) The utility shall identify as contingent plans those alternative resource plans that become preferred if the uncertain factors exceed the limits developed pursuant to section (2).

(B) The utility shall develop a process to pick among alternative plans, or to revise the alternative plans as necessary to help ensure reliable and low cost service should the preferred resource plan no longer be appropriate for any reason. The utility may also use this process to confirm the viability of a contingent resource plan identified pursuant to section (4)(A).

(C) Each contingency resource plan shall satisfy the fundamental objectives in 4 CSR 240-22.010(2) and the specific requirements pursuant to 4 CSR 240-22.070(1).

(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 (1) or more of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3) of this rule, including the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). This analysis shall use the same modeling procedure and assumptions described in section (4) and 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) The utility shall develop an implementation plan that specifies the major tasks, schedules and milestones 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 and demand-side rates, evaluations and research activities to improve the quality of demand-side resources;

(C) A schedule and description of all supply-side resource research, engineering, retirement, acquisition and construction activities, including research to meet expected environmental regulations;

(D) Identification of critical paths and major milestones for each demand-side resource acquisition project and each supply-side resource acquisition project, including decision points for committing to major expenditures;

(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 resource plans when the specified limits for uncertain factors are exceeded;

(F) A process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.

(7) The utility shall develop, document, officially adopt and implement a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by an officer of the utility 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 (1) of this rule;

(B) An implementation plan developed pursuant to the requirements of section (6) of this rule; and

(C) A set of contingency resource plans developed pursuant to the requirements of section (4) of this rule and the point at which the critical uncertain factors would trigger the utility to move to each contingency resource plan as the preferred resource plan.

(8) Evaluation of Demand-Side Programs and Demand–Side Rates. The utility shall develop evaluation plans for all demand-side programs and rates that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). The evaluation plans for each program and rate shall be developed before the program or rate is implemented, and shall be filed with the tariff application for the program or rate. The purpose of these evaluations shall be to develop the information necessary to improve the design of existing and future demand-side programs and demand-side rates, to improve the forecasts of customer energy consumption and responsiveness to demand-side programs and rates, and to gather data on the implementation costs and load impacts of demand-side programs and rates for use in cost-effectiveness screening and integrated resource analysis.

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

1. What are the primary market imperfections that are common to the target market segment?
2. Is the target market segment appropriately defined or should it be further subdivided or merged with other segments?
3. Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target segment?
4. Are the communication channels and delivery mechanisms appropriate for the target segment?
5. What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each end-use measure included in the program?

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

1. Impact evaluation methods. Comparisons of one (1) or both of the following types shall be used to measure program impacts in a manner that is based on sound statistical principles:
   A. Comparisons of pre-adoption and post-adoption loads of program or rate participants, corrected for the effects of weather and other intertemporal differences; and
   B. Comparisons between program and rate 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 and rate market potential, participation rates, utility costs, participant costs and total costs.

(9) If a preferred resource plan is replaced by a contingency resource plan as a result of the limits of one or more of the critical uncertain factors being exceeded or for some other reason, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which that contingency resource plan remains appropriate.

(10) 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 discussion and documentation of the analysis of the value of better information required by section (3), a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities;

(B) A discussion and documentation of the process used to select the preferred resource plan, including:

1. The relative weights given to the various performance measures;

2. The rationale used by utility decision-makers to:

A. Judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk; and

B. Determine that the preferred plan will perform adequately under extreme weather conditions; and

3. The names, titles and roles of the utility decision–makers in the preferred plan selection process;

(C) A description of any proposed load-building programs, a discussion of why these programs are judged to be in the public interest and, for all resource plans that include these 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.

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

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993. *Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)

4 CSR 240-22.080 Filing Schedule, Filing Requirements and Stakeholder Process

PURPOSE: This rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of this chapter. The purpose of the compliance review required by this chapter 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 requirements stated in 4 CSR 240-22.010(2)(A)-(C). This rule also establishes a mechanism for the utility to solicit and receive stakeholder input to its resource planning process.

(1) Each electric utility which sold more than one (1) million megawatt-hours to Missouri retail electric customers for calendar year 2009 shall make a filing with the commission every three (3) years on April 1. The electric utilities shall submit their triennial compliance filings on the following schedule:

(A) Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, or their successors, on April 1 of 2012 and every third year thereafter;

(B) The Empire District Electric Company, or its successor, on April 1 of 2013 and every third year thereafter; and

(C) Union Electric Company d/b/a AmerenUE, or its successor, on April 1 of 2014 and every third year thereafter.

(2) The utility's triennial compliance filings shall demonstrate compliance with the provisions of this chapter, and shall include at least the following items:

(A) Letter of transmittal expressing commitment to the approved preferred resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to bind and commit the utility to the resource acquisition strategy;

(B) If the preferred resource plan is inconsistent with the utility’s business plan, an explanation of the differences and why the differences exist;

(C) Technical volume(s) that fully describe and document the utility’s analysis and decisions in selecting its preferred resource plan and resource acquisition strategy.

1. The technical volume(s) shall include all information required by the rules CSR 240-22.030 through 240-22.070 and any other information considered by the utility to analyze and select its resource acquisition strategy.

2. The technical volume(s) shall be organized by chapters corresponding to the rules CSR 240-22.030 through 240-22.070.

3. A separate chapter shall be designated in the technical volume(s) to address special contemporary issues pursuant to 4 CSR 240-22.080(4) and input from the stakeholder group pursuant to 4 CSR 240-22.080(5). The chapter shall identify the issues raised, how the utility addressed them, and where in the technical volumes(s) the reports, analyses and all resulting actions are presented.

(D) The highly confidential form of the capacity balance spreadsheet completed in the specified format for the preferred resource plan and each candidate resource plan considered by the utility;

(E) An executive summary, separately bound and suitable for distribution to the public in paper and electronic formats. The executive summary shall be an informative non-technical description of the preferred resource plan and resource acquisition strategy. This document shall summarize the contents of the technical volume(s) and shall be organized by chapters corresponding to the rules CSR 240-22.030 through 240-22.070. The executive summary shall include:

1. A brief introduction describing the utility, its existing facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and the purpose of the resource acquisition strategy;
2. For each major class and for the total of all major classes, the base load forecasts for peak demand and for energy for the planning horizon, with and without utility demand-side resources and a listing of the economic and demographic assumptions associated with each load forecast;
3. A summary of the preferred resource plan to meet expected energy service needs for the planning horizon, clearly showing the demand-side resources and supply-side resources (both renewable and non-renewable resources), including additions and retirements for each resource type;
4. Identification of critical uncertain factors affecting the preferred resource plan;
5. For existing legal mandates, regulations, rules and approved cost recovery mechanisms, the following performance measures of the preferred resource plan for each year of the planning horizon:
   A. Estimated annual revenue requirement;
   B. Estimated impact on retail rates; and
   C. Estimated company credit rating;
6. If the estimated company credit rating in 5.C. of this rule is below investment grade in any year of the planning horizon, a description of any changes in legal mandates, regulations, rules and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting performance measures of the preferred resource plan;
7. Actions and initiatives to implement the resource acquisition strategy prior to the next triennial compliance filing;
8. A description of the major research projects and programs the utility will continue or commence during the implementation period, and the reasons for its selection; and

(F) Such other information or format as the Commission may determine.

(3) Beginning in 2012, on or about April 1 of every year in which the utility is not required to submit a triennial compliance filing, each electric utility shall host an annual update workshop with the stakeholder group.

(A) The purpose of the annual update workshop is to ensure that members of the stakeholder group have the opportunity to provide input and to stay informed regarding the:

1. Utility’s current preferred resource plan;
2. Status of the identified critical uncertain factors;
3. Utility’s progress in implementing the resource acquisition strategy;
4. Analyses and conclusions regarding any special contemporary issues that may have been identified pursuant to 4 CSR 240-22.080(4);
5. Resolution of any deficiencies or concerns pursuant to 4 CSR 240-22.080(15); and
6. Changing conditions generally.

(B) The utility shall prepare an annual update report with both a public version and a highly confidential version to document the information presented at the annual update workshop and shall file the annual update reports with the commission no less than 10 days prior to the annual update workshop. The depth and detail of the annual update report shall generally be commensurate with the magnitude and significance of the changing conditions since the last filed triennial compliance filing. If the current resource acquisition strategy has changed from that contained in the most recently filed triennial compliance filing, the annual update report shall describe the changes and provide updated capacity balance spreadsheets required pursuant to 4 CSR 240-22.080(2)(D). If the current resource acquisition strategy has not changed, the annual update report shall explicitly verify that the current resource acquisition strategy is the same as that contained in the most recently filed triennial compliance filing.

(C) The utility shall prepare a summary report of the annual update workshop and shall file it with the commission within 10 days following the workshop. The summary report shall list and describe any action items resulting from the workshop to be undertaken by the utility prior to next triennial compliance filing.

(D) Stakeholders may file comments with the commission concerning the utility's annual update report and summary report.

(4) It is the responsibility of each utility to keep abreast of evolving electric resource planning issues and to consider and analyze them in a timely manner in the triennial compliance filings and annual update reports. Commission staff may provide each electric utility with a list of special contemporary issues which the utility shall analyze and document in its next triennial compliance filing or next annual update report. The purpose of the special contemporary issues mechanism is to ensure that evolving regulatory, economic, financial, environmental, energy, technical or customer issues are adequately addressed by each utility in its electric resource planning. The special contemporary issues list will identify new and evolving issues, but may also include other issues such as unresolved deficiencies or concerns from the preceding triennial compliance filing. To develop the list of special contemporary issues:

(A) No later than October 1, public counsel and parties to the last triennial compliance filing of each utility may provide to the manager of the commission energy department suggested special contemporary issues for each utility to consider; and

(B) No later than November 1, staff shall provide a written list of special contemporary issues to each utility to consider in its next triennial compliance filing or annual update report or provide a written statement that there are no special contemporary issues.

(5) Each electric utility shall convene a stakeholder group to provide the opportunity for public input into electric utility resource planning in a timely manner that may affect the outcome of the utility resource planning efforts. The utility may choose to not incorporate some or all of the stakeholder group input in its analysis and decision-making for the triennial compliance filing.

(A) The utility shall convene at least one meeting of the stakeholder group prior to the triennial compliance plan filing to present an overview of its intended procedures, data sources, processes and findings to meet the objectives of 4 CSR 240-22.030 through 4 CSR 240-22.050. The stakeholders shall make a good faith effort to provide comments and identify where the utility's intended approaches may not meet the objectives of the rules.

(B) The utility shall convene at least one meeting of the stakeholder group prior to the triennial compliance plan filing to present a draft of the triennial compliance filing corresponding 4 CSR 240-22.030 through 4 CSR 240-22.050 and to present an overview of its proposed alternative resource plans and intended procedures and analyses to meet the objectives of 4 CSR 240-22.060 through 4 CSR 240-22.070. The stakeholders shall make a good faith effort to provide comments on the information provided by the utility, to identify additional alternative resource plans and to identify where the utility’s analyses and intended approaches may not meet the objectives of the rules.

(C) Within thirty (30) days of the last stakeholder group meeting pursuant to section (5)(B) of this rule, any stakeholder may provide the utility and other stakeholders with a written statement summarizing any potential deficiencies in or concerns with the utility’s proposed compliance with the electric resource planning rules. The utility has the opportunity to address the potential deficiencies or concerns identified by any stakeholder in its preparation of the triennial compliance filing.

(D) Any stakeholder input through the process described in section (5) of this rule does not preclude the stakeholder from filing reports in accordance with section (7) or section (8) of this rule.

(6) The commission will establish dockets for the purpose of receiving the triennial compliance filing and annual update reports including workshop summary reports of each affected electric utility. The commission will issue orders that establish an intervention deadline and provide for notice.

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

(8) Also within one hundred twenty (120) days after an electric utility's triennial compliance filing pursuant to this rule, the public counsel and any intervenor may file a report or comments. The report or comments, based on a limited review, may identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies or concerns which the public counsel or intervenor believes would prevent the utility's resource acquisition plan from effectively fulfilling the objectives of the electric resource planning rules.

(9) If the staff, public counsel or any intervenor finds deficiencies in or concerns with a triennial compliance filing, 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 and concerns. 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.

(10) If full agreement on remedying deficiencies or concerns 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 triennial 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.

11) 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 submitted within two (2) days of its triennial compliance or annual update filings in accordance with any protective order to the staff and public counsel, and to any intervenor within two (2) days of the intervenor signing and filing a confidentiality agreement, for use in its review of the periodic filings required by this rule. All information shall be labeled to reference the sections of the technical volumes(s) to which it s related, and all spreadsheets shall have all formulas intact. Each electric utility shall retain at least one (1) readable copy of the officially adopted resource acquisition strategy and all supporting information for at least the prior three (3) triennial compliance filings.

(12) If, between triennial filings, the utility’s business plan becomes inconsistent with the preferred resource plan, or if the utility determines 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, in writing, shall notify the commission within sixty (60) days of the utility's determination. The notification shall include a description of all changes, the impact of each change on the present value of revenue requirement and all other performance measures specified in the last filing pursuant to 4 CSR 240-22.080, and the rationale for each change.

(A) 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 in advance of its next regularly scheduled triennial compliance filing a revised resource acquisition strategy.

(B) If the utility decides to implement an option not identified pursuant to 4 CSR 240-22.070(10)(D), it shall give a detailed description of the option and why none of the contingency options identified in 4 CSR 240-22.070(10)(D) were chosen.

(13) Upon written application made at least twelve (12) months prior to a triennial compliance filing, and after notice and an opportunity for hearing, the commission may waive or grant a variance from a provision of this chapter 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 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 in total.

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

(15) The commission will issue an order which contains its findings regarding one or more of the following:

(A) That the electric utility's filing pursuant to this rule either does or does not demonstrate compliance with the requirements of this chapter, and that the utility's resource acquisition strategy either does or does not meet the requirements stated in 4 CSR 240-22.010(2)(A)--(C).

(B) That the commission agrees or disagrees with the joint filing on the remedies to the plan deficiencies or concerns developed pursuant to section (9) of this rule;

(C) That the commission agrees or disagrees with each party’s position for which full agreement on remedying deficiencies or concerns is not reached pursuant to section (10) of this rule; and

(D) That the commission establishes schedules for utility filings to remedy commission-determined deficiencies or concerns.

(16) In all future cases before the commission which involve a requested action that is affected by electric utility resources, preferred resource plans, or resource acquisition strategies, the utility must certify that the requested action is substantially consistent with the preferred resource plan specified in the most recent triennial compliance filing or annual update report.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993. *Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967. (Add authorities)