BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

COMMENTS OF THE OFFICE OF THE PUBLIC COUNSEL

The Missouri Office of the Public Counsel (Public Counsel or OPC) submits these comments on the Commission's proposed changes to Chapter 22 (4 CSR 240-22) of the Commission's Electric Utility Resource Planning Rules. These proposed rules were published in Volume 35, Number 23 of the Missouri Register on December 1, 2010.

General Comments

Public Counsel is generally supportive of proposed changes to Chapter 22 of the Commission's rules. The general direction of the proposed changes to Chapter 22 represent modifications that will bring the rules up-to-date with the environment in which electric utility resource planning takes place today. These changes include allowing more flexibility in the way that utilities perform the various tasks involved in the resource planning process. The rule has also been brought up-to-date by incorporating the increased range of legal mandates that affect resource planning in the areas of environmental regulation compliance and resource acquisition for demand-side and renewable resources.

An important part of improving the rules and bringing then up-to-date is to include provisions in the new rules that reflect lessons learned from applying the original IRP rules that were put in place in the early 1990s. Examples of lessons learned include providing more flexibility in the methods used to calculate avoided capacity and energy cost values that are used in the screening of demand-side resources. The proposed rules will alleviate the need for waivers that have been filed to permit utilities to use values from forward markets for capacity and energy instead of relying solely on cost based calculations of avoided costs. Another lesson learned that is reflected in the proposed rules is the requirements for utilities to examine financial ratios and credit metrics as important performance measures of alternative resource plans so we can avoid future filings where a utility has chosen an alternative resource plan that it would not have the financial capability to implement without major changes to Missouri laws pertaining to cost recovery.

The proposed rules represent the end result of a lengthy informal rulemaking process that occurred prior to the Commission's submission of the proposed rules to the Secretary of State. All parties were provided with numerous opportunities to have input into the Commission's proposed rules through the many opportunities for written comments and participation in workshops in Case No. EW-2009-0412. As this informal process took place, the Commission provided direction to its Staff on the general parameters of the proposed Chapter 22 rules. Public Counsel believes this informal process worked well and that the large amount of resources contributed by the many participants in this lengthy and time-consuming process helped the Commission to promulgate a good rule that will benefit Missouri consumers (1) by ensuring that they are served in a reliable and cost-effective manner and (2) by addressing and mitigating the risks of future changes in the electric utility operating environment.

While Public Counsel is generally supportive of the proposed rules, we are submitting detailed changes to the rule language that will improve and provide greater clarity to the rules. Attachment A includes OPC's suggested modifications to the proposed rules in "track changes" format. Attachment A includes proposed changes to the following rules:

- 4 CSR 240-22.020 Definitions;
- 4 CSR 240-22.045 Transmission and Distribution Analysis;
- 4 CSR 240-22.050 Demand-Side Resource Analysis;
- 4 CSR 240-22.060 Integrated Resource Plan and Risk Analysis;
- 4 CSR 240-22.070 Resource Acquisition Strategy Selection; and
- 4 CSR 240-22.080 Filing Schedule, Filing Requirements, and Stakeholder Process.

Public Counsel fully supports the other rules as proposed in Chapter 22 so we have not proposed any changes to the following rules:

- 4 CSR 240-22.010 Policy Objectives;
- 4 CSR 240-22.030 Load Analysis and *Load* Forecasting; and
- 4 CSR 240-22.040 Supply-Side Resource Analysis.

Proposed Changes to 4 CSR 240-22.020 Definitions

With the exception of the Definitions rule (4 CSR 240-22.020), Attachment A contains a copy of the entire proposed rule along with OPC's proposed changes in track changes format. The portion of Attachment A that pertains to the Definitions rule only contains those definitions that OPC proposes to modify or add to 4 CSR 240-22.020. This different approach to presenting OPCs' changes to 4 CSR 240-22.020 is due to the very limited changes that we are proposing to this rule in Chapter 22. The reasons for Public Counsel's proposed changes for five of the definitions in 4 CSR 240-22.020 (See page 1 of Attachment A) are as follows:

- (5) and (8) - Changes made to broaden these definitions and make the definitions consistent with the way the terms "concern" and "deficiency" are used in OPC's proposed changes to 4 CSR 240-22.080 (7),and (8). The limited definition in proposed rule does not make sense because it is not possible to determine ahead of time whether a deficiency in compliance with Chapter 22 or with the methodologies or analyses required would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in Chapter 22. Such a determination cannot be made until the analysis is redone to correct for the deficiency in compliance with Chapter 22 or with the methodologies or analyses required, and the results of the new analysis are reviewed.
- (27) Clarity and consistency with provisions for calculations of economic impacts of alternative resource plans in .060 (4)(C)2.
- (xx) Maximum achievable potential definition is added to the rule because it is used in place of the term "technical potential" in 4 CSR 240-22.060(3)(A)3. This definition comes from the Glossary (Appendix B) of the November 2007 Guide for Conducting Energy Efficiency Studies which was produced as part of the National Action Plan for Energy Efficiency.
- (53) Consistency with the provisions for special contemporary issues in 4 CSR 240-22.080 (4).

Proposed Changes to 4 CSR 240-22.045 Transmission and Distribution Analysis

4 CSR 240-22.045 is a new rule that includes some of the resource planning requirements related to transmission and distribution that were formerly in other areas of Chapter 22. This rule

also covers some new aspects of transmission and distribution planning in order to bring the rule up-to –date by reflecting changes in technology and regulation that have occurred since the IRP rules were promulgated by the Commission in the early 1990s. New technologies and emerging technologies have impacted the range of opportunities to achieve increased efficiencies in the transmission and distribution area and the potential for synergies between these areas and other aspects of resource planning. In addition, the evolution of how transmission planning and operations functions have been transferred to, and shared with, Regional Transmission Organizations (RTOs) has impacted the manner in which transmission plans are created, approved and executed for transmission facilities in and beyond the service territories of Missouri electric utilities. The reasons for Public Counsel's proposed changes to 4 CSR 240-22.045 (See pages 2 - 5 of Attachment A) are as follows:

- In 4 CSR 240-22.045(1), the term "fundamental planning objectives" has been changed to "fundamental planning objective" to reflect the fact that there is only a single "fundamental planning objective" which is referenced and defined in 4 CSR 240-22.010. 4 CSR 240-22.010 makes references to other "criteria" and "considerations" which could be characterized as objectives, but they should not be confused with the single "fundamental planning objective" which is set forth in 4 CSR 240-22.010. Public Counsel has corrected similar references to multiple "fundamental planning objectives" elsewhere in the proposed Chapter 22 rules by either changing the term "fundamental planning objectives" to "fundamental planning objective" or changing the term "fundamental planning objectives" to "planning objectives".
- The term "congestion and/or" was inserted in 4 CSR 240-22.045(3)(A)1 to reflect the fact that transmission upgrades are sometimes partially or fully justified by the economic value of relieving congestion on existing transmission facilities.
- Additions were made to the language in 4 CSR 240-22.045(3)(A)4 to ensure that the necessary analysis is performed to assess the impact on planning objectives and other considerations of having transmission built and owned by an affiliate of the electric utility instead of the electric utility. For example, if transmission is built and owned in a utility's service territory by an affiliate of the utility and that affiliate receives a rate of return incentive from FERC for that transmission, some party may argue that the

Commission is required to include cost of that that FERC incentive in the utility's bundled rates paid by Missouri ratepayers. The resource planning process should examine the costs for different options that may ultimately be passed on to Missouri customers in order to assess whether the utility has properly applied the requirement in 4 CSR 240-22.010(2)(B) for it to "use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan…"

- A change were made to the language in 4 CSR 240-22.045(3)(A)6 where the word "by" was changed to "for" to reflect the fact that the RTO generally does not build transmission itself but instead approves transmission projects that are built by others. The words "primarily for" were inserted because upgrades often have a mixture of reliability and economic benefits and to ensure that this provision did not apply solely to upgrades where 100% of the benefits were considered to be economic benefits.
- The word "Missouri" was added to 4 CSR 240-22.045(3)(B)2 to ensure that utilities have guidance from the Commission to focus on the impacts that proposed plans will have on their Missouri customers. Without this direction, some Missouri utilities can be expected to focus mostly on their fiduciary responsibility of maximizing the interests of their shareholders where those shareholders will be at the holding company level so that the multi-state operations of the holding company operating subsidiaries along with the non-regulated operations of the holding company will be taken into account.
- Changes and additions were made to the language in 4 CSR 240-22.045(3)(B) 3, 4, and 5 for the same reasons already noted in the bullets above.
- Changes were made to the language in sub-section (4)(C) of 4 CSR 240-22.045 to clarify the cost benefit analysis framework set forth in this sub-section and make sure that incremental benefits were calculated by comparing the benefits with one approach relative to the benefits of another approach.

Proposed Changes to 4 CSR 240-22.050 Demand-Side Resource Analysis

4 CSR 240-22.050 provides direction on the methodologies that are to be used by the utility in analyzing demand-side resources. Some changes were made to this rule (and other rules in Chapter 22) to clarify its meaning so it would not create confusion or be subject to future

misinterpretations and disputes and many of these changes are self-explanatory. The reasons for Public Counsel's substantial proposed changes to 4 CSR 240-22.050 (See pages 6 - 11 of Attachment A) are as follows:

- There are several places in the rule, including the purpose, where the term "maximum achievable potential" has been substituted for the term "technical potential." The reason for this change is that an assessment of the maximum achievable potential is more meaningful for planning purposes than an assessment of technical potential. For purposes of a bottom-up DSM potential study, it is generally necessary to assess the technical potential of a demand-side measure as the initial step in the process at creating an assessment of the more meaningful measures of DSM potential which are the realistic achievable potential and the maximum achievable potential. The realistic and maximum achievable potential values are inputs that are actually useful in integrated and risk analysis to examine the range of DSM resources that can actually be relied on as part of an integrated plan. The technical potential of a demand-side measure represents the outer bound of the impact from a measure that can be achieved through extraordinary means that could not realistically be applied in the real world and are often not cost effective, even when taking probable environmental costs into account.
- At several places in 4 CSR 240-22.050, the word "class" or "classes" has been revised for clarification purposes by preceding the word "class" or "classes" with the word "customer."
- In 4 CSR 240-22.050(3)(E), the term "such as rebates, financing and direct installations" was added to provide examples of the types of "multiple approaches" that are referenced in this part of the rule.
- In 4 CSR 240-22.050(3)(E), the term "describe and document the feasibility, cost-reduction potential and potential benefits of" was added to provide guidance on the type of analysis needed in this area to ensure that the outcomes of the resource planning process are consistent with the objectives and criteria set forth in 4 CSR 240-22.010.
- The concept of financing cost was added to 4 CSR 240-22.050(3)(G)5.B to make

sure that the costs associated with using financing to encourage customers' participation in demand-side programs are included in the utility's calculation of the cost of incentives in this part of the rule.

- In 4 CSR 240-22.050(4)(F) was changed to add guidance on the manner in which demand-side rates are considered by the utility's RTO so that the full range of issues considered by the RTO that are relevant to demand-side rates will be evaluated by the utility.
- In 4 CSR 240-22.050(5)(A)2, the word "other" was added to reflect the fact that fuel costs and emission allowance costs are within the broad category of costs referred to as "variable operating and maintenance costs."
- Item 4. was moved from 4 CSR 240-22.050(5)(B) to 4 CSR 240-22.050(5)(C) because the costs of incentive payments paid by ratepayers to the utility are not a net increase in the cost to society so they are labeled as transfer payments that should not be included in the total resource cost test calculation. Such costs do actually add to the cost of utility service that is paid by ratepayers so they need to be included in the utility cost test described in 4 CSR 240-22.050(5)(C).
- In 4 CSR 240-22.050(6)(C)1, the term "achievable potential of each demand-side candidate resource option or portfolio and the likelihood of occurrence for the different customer participation levels" was added to make it clear that both the range of possible outcomes plus the likelihood of outcomes at different points in the range is necessary to estimate "the impact of uncertainty." A clarification was made to 4 CSR 240-22.050(6)(C)2 for the same reason.

Proposed Changes to 4 CSR 240-22.060 Integrated Resource Plan and Risk Analysis

4 CSR 240-22.060 provides direction on the methodologies that are to be used by the utility in integrated resource plan and risk analysis. Some changes were made to this rule (and other rules in Chapter 22) to clarify its meaning so it would not create confusion or be subject to future misinterpretations and disputes and many of these changes are self-explanatory. The reasons for Public Counsel's substantial proposed changes to 4 CSR 240-22.060 (See pages 12 - 16 of Attachment A) are as follows:

- In 4 CSR 240-22.060(3), the term “and variation in the timing of resource acquisition” was added to stress the importance of varying not just the composition of supply and demand-side resources but also the timing of their acquisition in alternative resource plans to help determine an optimal alternative resource plan that best satisfies the objectives and criteria set forth in 4 CSR 240-22.010. A similar change was made to In 4 CSR 240-22.060(3)(A) for the same reason. The concept of optimization is also expressed in OPC’s changes to items 2, 3, and 4 of CSR 240-22.060(3)(A).
- The reasons for using “maximum achievable potential” instead of “technical potential” in CSR 240-22.060(3)(A)3 are the same reasons cited earlier in these comments for this change.
- There are a number of places in this rule where the word “rate” was replaced with ”demand-side rate” to avoid confusion with other uses of the word “rate” in this chapter of rules.
- CSR 240-22.060(4)(C)2 has an important change that is supported by the proposed change to the definition of the term “legal mandate” in CSR 240-22.020(27).
- Changes were made to sections (5), (6), and (7) to help clarify the distinction between “uncertain factors” and “critical uncertain factors” so that the process of determining which “uncertain factors” are deemed to be “critical uncertain factors” is easier to follow.

Proposed Changes to 4 CSR 240-22.070 Resource Acquisition Strategy Selection

4 CSR 240-22.070 provides guidance on the process for selecting a preferred resource plan and documenting the resource acquisition strategy that has been adopted by the utility. Most of the changes made to this rule (and other rules in Chapter 22) were made to clarify its meaning so it would not create confusion or be subject to future misinterpretations and disputes and many of these changes are self-explanatory. The reasons for Public Counsel’s only substantial proposed change to 4 CSR 240-22.070 (See pages 17 – 20 of Attachment A) are as follows:

- Section 9 of 4 CSR 240-22.070 was deleted because it was largely duplicative of section 12 of 4 CSR 240-22.080. The portion of section 9 that was not duplicative of section 12 of 4 CSR 240-22.080 was added to subsections (A) and (B) of 4 CSR 240-22.080(12).

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

4 CSR 240-22.060 provides direction on the methodologies that are to be used by the utility in integrated resource plan and risk analysis. Some changes were made to this rule (and other rules in Chapter 22) to clarify its meaning so it would not create confusion or be subject to future misinterpretations and disputes and many of these changes are self-explanatory. The reasons for Public Counsel's substantial proposed changes to 4 CSR 240-22.080 (See pages 21 - 27 of Attachment A) that were not already explained above are as follows:

- In sections (7) and (8) of 4 CSR 240-22.080, similar changes were made to the provisions in (7) that apply to Staff and the provisions in (8) that apply to Public Counsel and other interveners. Public Counsel is recommending the requirements for Staff, OPC and interveners to specify remedies and to provide workpapers supporting the cited deficiencies or concerns be removed from the rule. Both of these requirements were added at the request of the utilities and appear to be an attempt to turn the IRP review process where parties try to reach a joint agreement to resolve deficiencies from a dialogue between the parties into a preliminary step in the process of litigating differences. It should also be noted that both sections (7) and (8) of 4 CSR 240-22.080 refer to the "limited" review of the IRP filing that is to be performed by Staff, OPC and interveners. There is an inconsistency between expectation that a "limited" review would be performed, but the parties would be subject to the increased requirements to specify remedies and to provide workpapers. It should also be noted that Public Counsel has not observed problems with the current process where these requirements are not part of 4 CSR 240-22.080. Finally, does the Commission really want parties like Public Counsel with very limited resources to not raise deficiencies or concerns because of the added burden of the new requirements for specifying remedies and providing workpapers?

(5) Concern means concerns with the electric utility's compliance with the provisions of this chapter, any major concerns with the methodologies or analyses required to be performed by this chapter and anything that, while not rising to the level of a deficiency, may prevent the electric utility’s resource acquisition strategy from effectively fulfilling the objectives of Chapter 22.

(8) Deficiency means 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 anything that would cause the electric utility’s resource acquisition strategy to fail to meet the requirements identified in Chapter 22.

(27) Legal mandates include applicable state and federal executive orders, legislation, court decisions, and applicable state and federal administrative agency orders, rules, and regulations affecting electric utility cost recovery mechanisms, loads, resources or resource plans.

(xx) Maximum achievable potential means the amount of energy use that Demand-side resources can realistically be expected to displace assuming the most aggressive program scenario possible (e.g., providing end-users with payments for the entire incremental cost of more efficiency equipment).

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

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 describe and document its consideration of the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objective~~s~~ set out in 4 CSR 240-22.010. Each utility shall consider, at a minimum, improvements to the transmission and distribution networks that:

(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 preliminary supply-side candidate resource options.

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

(2) Avoided transmission and distribution cost. The utility shall develop, describe and document an avoided transmission capacity cost and an avoided distribution capacity cost. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 4 CSR 240-22.050(5)(A).

(3) Transmission analysis. The utility shall compile information and perform analyses of the transmission networks pertinent to the selection of a resource acquisition strategy. The utility and the Regional Transmission Organization (RTO) to which it belongs both participate in the process for planning transmission upgrades.

(A) The utility shall provide, and describe and document, its:

1. Assessment of the cost and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;

2. Assessment of transmission upgrades to incorporate advanced technologies;

3. Estimate of avoided transmission costs;

4. Estimate of the portion and amount of ~~incremental~~ costs of proposed regional transmission upgrades that would be allocated to the utility and if such costs may differ due to plans for the construction of facilities by an

affiliate of the utility then an estimate, by upgrade, of this cost difference;

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

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

(B) The utility may use the RTO transmission expansion plan in its consideration of the factors set out in section (3)(A) if all of the following conditions are satisfied:

1. The utility actively participates in the development of the RTO transmission plan;

2. The utility reviews the RTO transmission overall 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 Missouri customers; and

3. The utility reviews the portion of RTO transmission expansion plans each year within its service territory to assess whether the RTO transmission expansion plans pertaining to projects that are partially or fully driven by economic considerations (i.e. projects that are not solely or primarily based on reliability considerations), in the judgment of the utility decision makers, are in the interests of the utility's Missouri customers; and

~~3~~4. The utility documents and describes its review and assessment of the RTO overall and utility-specific transmission expansion plans.

5. If any affiliate of the utility intends to build transmission within the utility's service territory where the project(s) are partially or fully driven by economic considerations, then the utility shall explain why such affiliate built transmission is the interests of the utility's Missouri customers and describe and document the analysis performed by the utility to determine whether such affiliate built transmission is the interests of the utility's Missouri customers.

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

(D) The utility shall provide 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 requirements for firm transmission service from the point of delivery to the utility's load and requirements 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 requirements for firm transmission service to a point of delivery within the RTO footprint and requirements 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; and

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

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

(A) The utility shall develop, and describe and document, 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. The utility may use the RTO transmission expansion plan in its consideration of advanced transmission technologies if all of the conditions in (3)(B)1. through (3)(B)3. are satisfied.

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

(C) The utility shall describe and document its optimization of investment in advanced transmission and distribution technologies based on an analysis of:

1. Total costs and benefits, including:

a. Costs of the advanced grid investments;

b. Costs of the non-advanced grid investments;

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

d. Reduced supply-side 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~~ benefits 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 reduce cost in response to price signals;

d. Opportunity to reduce 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).

(D) Before the utility includes non-advanced transmission and distribution grid technologies in its triennial compliance filing or annual update filing 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. The utility may rely on a generic analysis as long as it verifies its applicability; and

2. Describe and document the analysis.

(E) The utility shall develop, describe and document the utility's cost benefit analysis and implementation of advanced grid technologies to include:

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

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

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

4 CSR 240-22.050 Demand-Side Resource Analysis

PURPOSE: This rule specifies the principles by which potential demand-side resource options shall be developed and analyzed for cost-effectiveness, with the goal of achieving all cost-effective demand-side savings. It also requires the selection of demand-side candidate resource options that are passed on to integrated resource analysis in 4 CSR 240-22.060 and an assessment of their ~~technical~~ maximum achievable 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 select the set of potential demand-side resources, and describe and document its selection:

(A) To provide broad coverage of:

1. Appropriate market segments within each major customer 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 the end uses which are to be considered in the utility's load analysis as listed in 4 CSR 240-22.030(4)(A)1; and

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

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

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

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

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

1. Reduce or manage energy use; or

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

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

provide copies of completed market research studies, pilot programs, pilot rates, test marketing programs and other studies as required by this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates.

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

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

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

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

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

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

(F) Evaluate, describe and document the feasibility, cost-reduction potential and potential benefits of statewide marketing and outreach programs, joint programs with natural gas utilities, upstream market transformation programs and other activities. In the event that statewide marketing and outreach programs are preferred, the utilities shall develop joint programs in consultation with the stakeholder group;

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

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

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

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

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

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

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

B. The cost of incentives paid by the utility to customers or utility financing to encourage participation~~e~~ in the potential demand-side program.

The utility shall consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program, with ~~commensurate~~ corresponding adjustments to the maximum achievable~~technical~~ potential and the realistic achievable potential of that potential demand-side program;

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

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

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

F. Other costs identified by the utility.

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

(I) The utility shall describe and document how it performed the assessments and developed the estimates pursuant to section (G), and shall provide documentation of 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 utility shall describe and document its demand-side rate planning and design process, and shall include at least the following activities and elements:

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

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

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

(D) Estimate the input data and other 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 corresponding ~~commensurate~~ adjustments to the ~~technical~~ maximum achievable potential and the realistic achievable potentials of that potential demand-side rate;

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

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

D. Other costs identified by the utility.

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

(F) Evaluate how each demand-side rate would be considered by the utility's RTO in resource adequacy determinations, eligibility to participate as a demand response resource in RTO markets for energy, capacity, and ancillary services, and any other considerations; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. The impact of uncertainty concerning the cost effectiveness by identifying uncertain factors affecting ~~which~~ the cost effectiveness of each demand-side candidate resource~~s~~ option or portfollio ~~are cost effective~~. The utility shall identify how the menu of cost effective demand side measures changes with these uncertain factors and shall estimate how these changes affect the load impact estimates associated with the demand-side candidate resource options and the likelihood of such uncertain factors varying from expected levels.

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

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

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 alternative 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. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that the satisfy all of the planning objectives and priorities.

(2) Specification of Performance Measures. The utility shall specify, describe and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.

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

1. Present worth of utility revenue requirements, with and without any rate of return or financial performance incentives for demand-side resources the utility is planning to request;

2. Present worth of probable environmental costs;

3. Present worth of out-of-pocket costs to participants in demand-side programs and demand-side rates;

4. Levelized annual average rates;

5. Maximum single-year increase in annual average rates;

6. Financial ratios (e.g. pretax interest coverage, ratio of total debt to total capital, ratio of net cash flow to capital expenditures) or other credit metrics indicative of the utility's ability to finance alternative resource plans; and

7. Other measures that utility decision-makers believe are appropriate for assessing the performance of alternative 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 resources 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(6). Supply-side resources are the supply-side candidate resource options developed in 4 CSR 240-22.040(4). The goal is to develop a set of alternative plans based on substantively different mixes of supply-side resources and demand-side resources and variations in the timing of resource acquisition to assess their relative performance under expected future conditions as well as their robustness under a broad range of future conditions.

(A) The utility shall develop, and describe and document, at least one alternative resource plan, and as many as may be needed to assess the range of ~~resource~~ options for the choices and timing of resources, for each of the following cases. Each of the alternative resource plans for cases pursuant to (A)1. through (A)5. of this section shall provide resources to meet at least the 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 legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources. This constitutes the compliance benchmark resource plan for planning purposes;

2. Utilize only an optimal combination of renewable energy resources, up to the maximum potential capability of renewable resources in each year of the planning horizon, if that results in more renewable energy resources than the minimally compliant plan. This constitutes the aggressive renewable energy resource plan for planning purposes;

3. Utilize only an optimal combination of demand-side resources, up to the maximum ~~technical~~ achievable potential of demand-side resources in each year of the planning horizon, if that results in more demand-side resources than the minimally compliant plan. This constitutes the aggressive demand-side resource plan for planning purposes;

4. In the event that legal mandates identify energy resources other than renewable energy or demand-side resources, utilize only the an optimal combination of other energy resources, up to the maximum potential capability of the other energy resources in each year of the planning horizon, if that results in more of the other energy resources than the compliance benchmark resource plan. For planning purposes, this constitutes the aggressive legally mandated other energy resource plan;

5. Optimally comply with legal mandates for demand-side resources, renewable energy resources, and other targeted energy resources. This constitutes the optimal compliance resource plan, where every legal 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~~ commission 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 and other retrofits on generation plants to meet environmental requirements; and

3. The conclusion of any currently implemented demand-side resources.

(D) The utility shall provide a description of each alternative resource plan including the type and size of each demand-side resource and supply-side resource addition and a listing of the sequence and schedule for the end of life of existing resources and for the acquisition of each new resource.

(4) Analysis of Alternative Resource Plans. The utility shall describe and document its assessment of 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. The analysis shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. The analysis shall treat supply-side and demand-side resources on a logically consistent and economically equivalent basis, such that the same types or categories of costs, benefits and risks shall be considered, and such that these factors shall be quantified at a similar level of detail and precision for all resource types. The utility shall provide the following information:

(A) 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;

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

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

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

3. The composition, by supply-side resource, of the capacity as measured at the customers' meters 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 demand-side rate, of the annual energy provided by demand-side resources;

6. The composition, by supply-side resource, of the annual energy as measured at the customer's meters provided by supply-side resources. Existing supply-side resources may be shown as a single resource;

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

8. Annual probable environmental costs; and

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

(C) The analysis of economic impact of alternative resource plans, calculated with and without utility financial incentives for demand-side resources, shall provide comparative estimates for each year of the planning horizon:

1. For the following performance measures for each year;

A. Estimated annual revenue requirement;

B. Estimated annual average rates and ~~impacts on retail rates~~percentage increase in the average rate from the prior year; and

C. Estimated company financial ratios and credit metrics.

2. If the estimated company financial ratios in 1.C. of this section are below investment grade in any year of the planning horizon, a description of any changes in legal mandates 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 in 1.A. through 1.C. of the alternative resource plans that are associated with the necessary changes in legal mandates and cost recovery mechanisms.

(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 renewable energy legal mandates;

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

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

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

(5) The utility shall describe and document its selection of the uncertain factors that are critical to the performance of the alternative resource plans. The utility shall consider, for potential designation as critical uncertain factors, 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;

(D) Real fuel prices and ~~R~~relative (e.g. coal vs. natural gas 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 value 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 demand-side rates;

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

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

(6) The utility shall describe and document its assessment of the impacts of ~~critical~~ uncertain factors analyzed pursuant to section (5) of this rule on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3) to identify those uncertain factors that are deemed critical. ~~and analyze the risks associated with alternative resource plans.~~ This assessment shall explicitly describe and document the probabilities that utility decision-makers assign to each critical uncertain factor.

(7) The utility shall analyze the risks associated with alternative resource plans. 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. The utility shall describe and document its risk assessment of each alternative resource plan.

(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.

(C) The utility shall provide:

1. A discussion of the method the utility used to determine the cumulative probability.

A. 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; and

B. Analyses supporting the utility’s choice of ranges and probabilities for the uncertain factors;

2. Plots of the cumulative probability distribution of each distinct performance measure for each alternative resource plan;

3. For each performance measure, a table that shows the expected value and the risk of each alternative resource plan; and

4. A plot of the expected level of annual unserved hours for each alternative resource plan over the planning horizon.

4 CSR 240-22.070 Resource Acquisition Strategy Selection

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 the demand-side resources that are included in the resource acquisition strategy.

(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 utility shall describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision-makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall provide the names, titles, and roles of the utility decision–makers in the preferred resource plan selection process. 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 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 comply with legal mandates and, in the judgment of the utility decision-makers, are consistent with the public interest and achieve 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 forecasted under extreme weather conditions pursuant to 4 CSR 240-22.030(8)(B) for the implementation period. If the utility cannot affirm the sufficiency of resources, it shall consider an alternative resource plan or modifications to its preferred resource plan that can meet extreme weather conditions.

(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 describe and document its assessment of whether, and under what circumstances, other uncertain factors associated with the preferred resource plan could materially affect the performance of the preferred resource plan relative to alternative resource plans.

(3) The utility shall describe and document its quantification of 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. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities.

(4) The utility shall describe and document its contingency resource plans in preparation for the possibility that the preferred resource 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 contingency resource plans those alternative resource plans that become preferred if the critical uncertain factors exceed the limits developed pursuant to section (2).

(B) The utility shall develop a process to pick among alternative resource plans, or to revise the alternative resource 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 contingency resource plans identified pursuant to subsection (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 4 CSR 240-22.060(4). The utility shall describe and document—
(A) Its analysis of load building programs, including the following elements:
1. Estimation of the impact of load-building programs on the electric utility's summer and winter peak demands and energy usage;
2. A comparison of annual average rates in each year of the planning horizon for the resource plan(s) with and without the load-building program;
3. A comparison of the probable environmental costs of the resource plan(s) in each year of the planning horizon with and without the proposed load-building program;
4. A calculation of the performance measures and risk by year; and
5. An assessment of any other aspects of the proposed load-building programs that affect the public interest; and
(B) All current and 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.

(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 utility shall describe and document its implementation plan, which 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 implementation of each demand-side resource and each supply-side resource, including decision points for committing to major expenditures;
(E) A description of adequate competitive procurement policies to be used in the acquisition and development of supply-side resources;
(F) 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; and
(G) 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, describe and 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 identification of **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 describe and document its evaluation plans for all demand-side programs and demand-side 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 evaluate the cost-effectiveness and **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 demand-side rates, and to gather data on the implementation costs and load impacts of demand-side programs and demand-side rates for use in** future **cost-effectiveness screening and integrated resource analysis.**

(A) Process Evaluation. Each demand-side program and demand-side 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 market 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 market segment?

4. Are the communication channels and delivery mechanisms appropriate for the target market 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 demand-side rate included in the utility's preferred resource plan to a reasonable degree of accuracy.

1. Impact evaluation methods. At a minimum, comparisons of one (1) or both of the following types shall be used to measure program and rate impacts in a manner that is based on sound statistical principles:

A. Comparisons of pre-adoption and post-adoption loads of program or demand-side **rate participants, corrected for the effects of weather and other intertemporal differences; and**

B. Comparisons between program and demand-side **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:

A. Monthly billing data, hourly load data, **load research data, end-use load metered data, building and equipment simulation models, and survey responses; or**

B. Audit and survey **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 demand-side rate market potential, participation rates, utility costs, participant costs, and total costs.

~~(9) If, during the implementation period, a preferred resource plan is replaced by a contingency resource plan as a result of the limits of one (1) 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.~~

4 CSR 240-22.080 Filing Schedule*, Filing* Requirements*, and Stakeholder 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. Companies submitting their triennial compliance filings on the same schedule may file them jointly. 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, 2012, and every third year thereafter;

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

(C) Union Electric Company d/b/a Ameren Missouri, or its successor, on April 1, 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 documentation and information specified in 4 CSR 240-22.030–4 CSR 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 4 CSR 240-22.030–4 CSR 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 4 CSR 240-22.030–4 CSR 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 base 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 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~~ level of average retail rates and percentage change from prior year; and

C. Estimated company financial ratios;

6. If the estimated company financial ratios in subparagraph (2)(E)5.C. of this rule are below investment grade in any year of the planning horizon, a description of any changes in legal mandates 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; and

8. A description of the major research projects and programs the utility will continue or commence during the implementation period; 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. The utility at its discretion may host additional update workshops when conditions warrant. Any additional update workshops shall follow the same procedures as the annual update workshop.

(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(16); 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 twenty (20) 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 or annual update filing. If the current resource acquisition strategy has changed from that contained in the most-recently-filed triennial compliance filing or annual update 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 or annual update filing.

(C) The utility shall prepare a summary report that shall list and describe any action items resulting from the workshop to be undertaken by the utility prior to next triennial compliance filing or annual update filing. The summary shall be filed within ten (10) days following the workshop. If there are no changes as a result of the workshop, the utility is required to file a notice that it will not be making any changes to its annual update report.

(D) Stakeholders may file comments with the commission concerning the utility’s annual update report and summary report within thirty (30) days of the utility’s filing of the summary report.

(4) It is the responsibility of each utility to keep abreast of evolving electric resource planning issues and to consider and analyze these issues in a timely manner in the triennial compliance filings and annual update reports. An order containing a list of special contemporary issues shall be issued by the commission for each utility to analyze and document in its next triennial compliance filing or next annual update report. The purpose of the special contemporary issues lists 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. Each 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 September 15, staff, public counsel, and parties to the last triennial compliance filing of each utility may file suggested special contemporary issues for each utility to consider;

(B) Not later than October 1, the utilities, staff, public counsel, and parties to the last triennial compliance filings may file comments regarding the special contemporary issues filed on September 15; and

(C) No later than November 1, an order containing a list of special contemporary issues shall be issued by the commission for each utility to analyze and document in its next triennial compliance filing or annual update report. The commission shall not be limited to only the filed suggested special contemporary issues. If the commission determines that there are no special contemporary issues for a utility to analyze, an order shall be issued by the commission stating 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 (1) meeting of the stakeholder group prior to the triennial compliance plan filing to present a draft of the triennial compliance filing corresponding 4 CSR 240-22.030–4 CSR 240-22.050 and to present an overview of its proposed alternative resource plans and intended procedures and analyses to meet the requirements of 4 CSR 240-22.060 and 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.

(B) Within thirty (30) days of the last stakeholder group meeting pursuant to subsection (5)(A) 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.

(C) 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 (8) of this rule.

(6) The commission will establish dockets for the purpose of receiving the triennial compliance filings. Unless the commission specifies otherwise, the docket of the triennial compliance filing of each affected utility shall remain open to receive annual update reports including workshop summary reports, notifications of changes to the preferred plan, and other relevant documents submitted between triennial compliance filings. The commission will issue orders that establish an intervention deadline and provide for notice.

(7) The staff shall conduct a limited review of 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 and ~~shall~~ may provide ~~at least one (1)~~ suggested remedies~~y~~ for each identified deficiency. Staff may also identify concerns with the utility's triennial compliance filing and ~~shall~~ may provide ~~at least one (1)~~ suggested remedies~~y~~ for each identified concern. ~~Staff shall provide its workpapers related to each deficiency or concern to all parties within ten (10) days of the date its report is filed.~~ 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 or concerns which the public counsel or intervenor believes could prevent the utility's resource acquisition ~~plan~~ strategy from effectively fulfilling the objectives of the electric resource planning rules. Public counsel or intervenors ~~shall~~ may provide ~~at least one (1)~~ suggested remed~~y~~iesy for each identified deficiency or concern. ~~Public counsel or any intervenor shall provide its workpapers related to each deficiency or concern to all parties within ten (10) days of the date its report is filed.~~

(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 is 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 compliance filings, the utility's business plan or acquisition strategy becomes materially inconsistent with the preferred resource plan, or if the utility determines that the preferred resource plan or acquisition strategy is no longer appropriate, either due to the limits identified pursuant to 4 CSR 240-22.070(2) 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 to the preferred plan and acquisition strategy, 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 resource plans identified pursuant to 4 CSR 240-22.070(4), the utility shall file for review a revised resource acquisition strategy. In this filing, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the new alternative resources plan remains appropriate.

(B) If the utility decides to implement a resource plan not identified pursuant to 4 CSR 240-22.070(4) or changes its acquisition strategy, it shall file for review a revised resource acquisition strategy and give a detailed description of the revised resource ~~plan or~~ acquisition strategy and explain why none of the contingency resource plans identified in 4 CSR 240-22.070(4) were chosen.In this filing, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the new alternative resource plan remains appropriate.

(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 4 CSR 240-22.030–4 CSR 240-22.070 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) An electric utility which sells less than seven (7) million megawatt-hours to Missouri retail electric customers for the previous calendar year may apply for a waiver allowing it to conduct an annual update workshop pursuant to section (3) of this rule in place of its scheduled triennial compliance filing pursuant to section (1) of this rule, if the utility has no unresolved deficiencies or concerns from its prior triennial plan filing or annual update filing that materially affect its resource acquisition strategy. 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 allow the utility to conduct the annual update workshop process in lieu of submitting its triennial compliance filing. No more than one (1) such waiver may be granted consecutively between triennial compliance filings.

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

(16) The commission will issue an order which contains its findings regarding at least one (1) of the following options:

(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.

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

(C) That the commission understands that full agreement on remedying deficiencies or concerns is not reached and pursuant to section (10) of this rule, the commission will issue an order which indicates on what items, if any, a hearing(s) will be held and which establishes a procedural schedule; and

(D) That the commission establishes a procedural schedule for filings and a hearing(s), if necessary, to remedy deficiencies or concerns as specified by the commission.

(17) In all future cases before the commission which involve a requested action that is affected by electric utility resources, preferred resource plan, or resource acquisition strategy, 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. If the requested action is not substantially consistent with the preferred resource plan, the utility shall provide a detailed explanation.