BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

COMMENTS OF KANSAS CITY POWER & LIGHT COMPANYAND
KCP&L GREATER MISSOURI OPERATIONS COMPANY
TO PROPOSED REVISIONS OF THE CHAPTER 22
ELECTRIC UTILITY RESOURCE PLANNING RULES

Kansas City Power & Light Company ("KCP&L") and KCP&L Greater Missouri Operations Company ("GMO") (collectively, the "Companies") hereby submit comments in response to the Missouri Public Service Commission ("Commission" or "PSC") Proposed Amendments and Proposed Rule revising 4 CSR 240-22, Electric Utility Resource Planning Rules ("EURP"or "IRP"), published in the *Missouri Register* on December 1, 2010. The Companies respectfully request that the Commission consider these comments prior to taking further steps to finalize the rules.

General Comments

The Companies first want to acknowledge the work conducted by the PSC Staff. This process has a long and complicated past. In arriving at the current proposed rule, the Staff and workshop participants spent many, many hours working on a proposal. File No. EW-2009-0412, IRP Rulemaking Workshops, was opened by the PSC on May 15, 2009, to serve as a repository file regarding the Chapter 22 EURP revisions workshops. On May 20, 2009, the Commission issued *it's Notice of Repository File Regarding the Chapter 22 Electric Utility Resource Planning Revisions Workshops* in File No. EW-2009-0412, stating: "The Commission's Staff will be hosting a series of workshops to consider changes to the Commission regulation that requires Missouri's investor-owned electric utilities to consider and analyze their resource plans, resource acquisition strategies, and investment decisions with the intent to provide safe, reliable and efficient energy services to the public at just and reasonable rates."

Over a period of approximately eighteen months, workshops were held and comments were supplied in an effort to find common ground to revise Chapter 22 rules. Some measure of the monumental task to draft EURP rule revisions can be seen in looking at the attendee list from the July 30-31, 2009, Rulemaking Workshop. Thirty-seven individuals representing fifteen distinct parties are listed, and every party brought to the table its unique objectives and perspectives. During the workshop process, KCP&L and GMO, through the Missouri Energy Development Association ("MEDA"), provided an alternative rule designed to allow utilities the flexibility to plan in the manner most appropriate for each utility and to still provide Staff and any intervenor with the information necessary to participate in the planning process and evaluate the end result, *i.e*. the plan. KCP&L and GMO continue to support the rule proposed by MEDA (attached) as an alternative to the highly prescriptive published rule before us.

Unfortunately, further complicating this IRP rule revision, new rules designed to implement Section 393.1075, The Missouri Energy Efficiency Investment Act in case EX-2010-0368, rely on the utility's resource plan for cost recovery, as does the newly adopted Electric Utility Renewable Energy Standard Requirements rule found in 4 CSR 240-20.100. Incorporating ties to the utility resource plan in the MEEIA and the Renewable Energy Standard rules makes IRP filings and the resulting preferred plan, by default, a factor in revenue cases. It is worthwhile to note that there is no provision for any level of PSC approval of the preferred plan or any component of the preferred plan per this proposed Chapter 22 revision, but the preferred plan will be key to revenue recovery as it relates to demand-side investments and renewable energy supply investments.

KCP&L and GMO believe there should be a provision in the revised rule that would allow the utilities to request decisional prudence rulings for major investments that are planned in the near term. Considering the elevated status of the IRP in the determination of revenue requirements related to demand-side investments and renewable energy investments, the ability to request decisional prudence for major investments in these arenas is critical.

Additional Comments

4 CSR 240-22.020 Definitions

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

Major class is defined as a cost-of-service class of the utility. For KCP&L, these classes would include Residential, Small General Service, Medium General Service, Large General Service, Large Power and lighting. For GMO the classes would be the same with the exception of Medium General Service. A major problem with the cost-of-service classes, is that customers frequently switch from one tariff to another to lower their bills. This switching can make these classes unstable. The cost-of-service classes are separated by size as opposed to business activity. In any of these classes, there is a huge array of different business activities.

In the current rule, major classes are residential, commercial and industrial. Traditionally GMO and KCP&L have prepared their budgets by economic sector--residential, commercial (secondary and primary voltages), and manufacturing (secondary and primary voltages) because this division creates the most homogenous groups of customers. Also, most of the economic data and forecasts are provided by economic sector. For example, Moody's Economy.com provides the Companies with a forecast that includes manufacturing and non-manufacturing employment and manufacturing and non-manufacturing Gross Regional Product. Also, the Companies use forecasts of energy efficiency trends from the US DOE and their models are separated by economic sector. The new rule would require the Companies to prepare separate budget and IRP forecasts, unless a waiver is granted. This will result in duplicative data bases, additional work, and forecasts that may not be in sync. The Companies recommend this new level of detail be eliminated.

4 CSR 240-22.040 Supply-Side Resource Analysis

The Purpose statement at the beginning of Section 22.040 indicates that the proposed rule makes "transmission planning a more integral part of the supply-side analysis." This statement captures a theme that runs throughout the proposed rules in connection with transmission planning. Although this appears to be an appropriate goal on the surface, it raises numerous practical problems in the context of the current structure of the electric industry. Transmission options and projected transmission costs can and should be analyzed and considered in developing an integrated supply-side plan. On the other hand, it is not feasible to conduct a fully integrated analysis because of several fundamental issues:

(1) The Companies are members of, and participate fully in, a Regional Transmission Organization ("RTO") that develops transmission solutions for the region. This requires the RTO to balance the interests of its various member companies when it prepares its region-wide transmission plans. Some of the planned facilities may serve to enhance the Companies' ability to meet their supply-side objectives, some may simply add cost to the Companies while having a relatively neutral supply-side impact, and others may even limit the Companies' ability to meet

their supply-side objectives. While the Companies have a voice in this planning process, they cannot disproportionately influence the results of regional planning in their favor. Furthermore, the Companies' own transmission facilities are under the functional control of this RTO. As such, the Companies' locally-developed projects are subject to review and modification by the RTO in view of regional reliability issues and impacts on the grid. Because of the RTO's responsibility for regional projects, the Companies cannot ensure that specific regional projects that may be beneficial to themselves are built without resorting to project sponsorship. Such sponsorship can create free-ridership by retail customers of other companies due to subsidization by the Companies' retail customers.

(2) In order to reasonably ensure that the Companies can use and benefit from a project on the supply side, they need to secure service related to that project through a generator interconnection agreement, a point-to-point transmission service agreement, or a network transmission service agreement. Even sponsorship of a project does not convey a firm right to benefit from it unless such an agreement is in place. Obtaining a generator interconnection agreement requires an entity to enter the interconnection queue, a process that involves months of study and administrative costs borne by the requester. Obtaining long-term point-to-point or network transmission service requires an entity to enter the RTO's aggregate study, a process that involves months or even years of study and administrative costs borne by the requester. The implementation of any transmission options studied in the development of an integrated resource plan can be contingent on whether: (1) the RTO ultimately grants the requested service at a cost that is even comparable to the estimate contained in the utility's integrated resource plan, (2) the RTO authorizes the construction of the proposed facilities, and (3) the RTO and the designated constructor of the facilities are able to accomplish the project in the required time frame.

Because of the interrelated nature of the grid and transmission development, there is not a means to develop project cost and timing information with a high degree of confidence outside of the RTO's study procedures described above. Furthermore, due to the long lead time and cost of the generator interconnection study and aggregate study, these procedures simply cannot be performed for the multiple solutions being studied in an integrated resource plan. Therefore, the feasibility and cost of the proposed transmission facilities will be highly uncertain at the time the integrated resource plan is prepared.

Given the limitations and issues discussed above, how should the proposed planning rules be modified for the purpose of integrating transmission factors with supply-side options? The Companies respectfully submit that several general modifications are appropriate, each of which may affect several sections of the proposed rules:

(1) Include a reference to the RTO (or other applicable transmission planning authority if the goal is to couch the rules in a flexible manner) along with the utility whenever transmission planning requirements are addressed.

(2) Do not imply that the local utility has full control of transmission planning that impacts its supply-side solutions. It does have a degree of local planning responsibility, but the RTO is the ultimate planning authority for the bulk electric transmission system.

(3) Recognize that, because of the RTO transmission planning authority, the transmission system is planned with regional as well as local considerations and that many transmission facility improvements directed on that system, even those on the utility's owned facilities, may not support the supply-side objectives of the utility. Furthermore, any set of transmission plans developed by the RTO in a single year may not benefit the utility on a net

basis. Benefits can be properly evaluated only over the long-term, including multiple planning cycles.

(4) Qualify the language addressing the cost of transmission development to acknowledge that the cost of transmission solutions is subject to tremendous uncertainty due to the integrated nature of the grid and the dynamic processes of continuing transmission development and analysis of numerous service requests by the RTO. The transmission development and service requests are necessary to meet the diverse needs of the region, including new generation resources, grid reliability, integration of renewable sources, and transmission congestion relief.

(5) Any language addressing the deployment and evaluation of advanced transmission technology should be framed primarily in the context of RTO planning rather than suggesting that the utility can independently optimize its investment in such facilities.

(6) Include requirements that the utility utilize estimates of transmission costs associated with its various supply-side options. However, explicitly acknowledge that those estimates are subject to significant error due to factors beyond the control of the utility, as discussed above.

4 CSR 240-22.045 Transmission and Distribution Analysis

Section 240-22.045(3)(D)5 of the Integrated Resource Planning Rules states the following:

> (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.
> (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:
> <u>5. The estimated total cost of each transmission upgrade and estimated congestion costs</u>; (Emphasis added).

These comments are concerned with the “estimated congestion costs” of this section of the proposed rules. Transmission congestion is a phenomenon of RTO market operations and is a factor considered during the RTO process to develop region-wide transmission projects. Congestion can fluctuate on a very short time scale (less than an hour) in both level of congestion (MW) and prices associated with congestion ($/Mwh). While transmission congestion costs can be identified in real time market operations, they cannot be forecast or estimated using traditional planning tools. Future transmission congestion costs can only be estimated by a fully integrated resource and transmission simulation tool that projects market operations on an hourly basis. This type of simulation tool requires comprehensive data and modeling detail for the entire RTO region and interconnected systems and generally is available only at the RTO level and not available to individual utilities. Even then, congestion costs are difficult to estimate at RTO seams due to competing markets operating on different sides of the boundaries between RTOs. It would require significant resources and expense to develop an estimate of future transmission congestion costs and even then the resulting estimate would have significant uncertainty. Therefore, the estimate would entail substantial cost and produce minimal value in the IRP process.

For these reasons, the Companies recommend removing the “and congestion costs” part of 240-22.045(3)(D)5 of the Integrated Resource Planning Rules.

4 CSR 240-22.060 Integrated Resource Plan and Risk Analysis

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

The Companies are unsure what is meant by this statement. The Companies’ understanding of the term “levelized” as used previously in the rule is that it is a simple average, and not discounted.

> (3) Development of Alternative Resource Plans...
> (A) The utility shall develop, and…
> 1. Minimally comply with legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources...

The Companies believe complying with legal mandates is a "given" and this statement is unnecessary.

> (4) Analysis of Alternative Resource Plans.
> (B) For each alternative resource plan, a plot of each of the following over the planning horizon:
> 3. The composition, by supply-side resource, of the capacity at the customers' meters provided by supply-side resources.

The designation of "capacity at the customers' meters" assumes that physical capacity can be assigned to an individual customer or group of customers. The Companies suggest replacing with "capacity supplied to the transmission grid".

> (4)(B) 6. The composition, by supply-side resource, of the annual energy at the customer's meters provided by supply-side resources.

The designation of "energy at the customers' meters" assumes that physical energy can be assigned to an individual customer or group of customers. The Companies suggest replacing with "energy supplied to the transmission grid, less losses".

Conclusion

The Companies respectfully request that the Commission consider the foregoing comments when finalizing the proposed amendments and proposed rule addressed herein.

Respectfully submitted,

*/s/ Roger W. Steiner*______________

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**ATTORNEYS FOR KANSAS CITY POWER & LIGHT COMPANY AND
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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been hand-delivered, emailed or mailed, postage prepaid, this 3rd day of January, 2011, to all counsel of record.

*/s/ Roger W. Steiner*_______________
Roger W. Steiner

ATTORNEYS FOR KANSAS CITY POWER & LIGHT COMPANY AND
KCP&L GREATER MISSOURI OPERATIONS COMPANY

4 CSR 240-22.010 Policy Objectives

(1) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest, which requires a balancing of the interests of both customers and electric utility shareholders. This objective requires that the utility shall—

(A) Consider and analyze demand-side and supply-side alternatives consistent with federal and state energy policy;

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

(C) Explicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs.

4 CSR 240-22.020 Definitions

(1) **Acknowledge** -The plan seems reasonable to the Commission at the time the acknowledgement is given. Acknowledging a plan is not pre-approval of any resource decision but in rate making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with an acknowledged integrated resource plan.

(2) **Avoided Cost**-The costs avoided by substituting demand-side resources for existing and new supply-side resources.

(3) **Candidate Resource Plans-**Alternative resource plans that pass the screening test required by 4 CSR 240-22.060.

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

(5) **Chance Node**-A decision-tree fork consisting of two (2) or more branches that represent the range and number of relevant potential outcomes for an uncertain factor.

(6) **Compliance Filing-**The filing required by 4 CSR 240-22.080.

(7) **Contingency Option-**An alternative choice, decision or course of action designed to enhance the utility's ability to respond quickly and appropriately to events or circumstances that would render the preferred resource plan obsolete.

(8) **Concern-**Where the consequence of the noncompliance with 4 CSR 240-22 is not substantial enough to cause the electric utility to select an alternative resource plan as the electric utility's preferred resource plan.

(9) **Deficiency**-Noncompliance with the requirements of the rules contained in 4 CSR 240-22 the consequence of which is substantial enough that compliance would cause the electric utility to select an alternative resource plan as the electric utility's preferred resource plan.

(10) **Demand-**The rate of electric power use measured in kilowatts (kW).

(11) **Demand-side Measure-**Synonymous with end-use measure.

(12) **Demand-side Resource** -Any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the electric meter, including, but not limited to energy efficiency measures, load management, demand response, and interruptible or curtailable load.

(13) **Electric Utility or Utility-**Any electrical corporation as defined in section 386.020, RSMo which is subject to the jurisdiction of the Commission.

(14) **End-use Measure-**An energy-efficiency measure or an energy-management measure.

(15) **Energy-**The total amount of electric power that is generated or used over a specified interval of time measured in kilo-watt-hours (kWh).

(16) **Energy-efficiency Measure**-Any measures that reduce the amount of electricity required to achieve a given end use.

(17) **Energy-management Measure-**Any device, technology, rate structure or operating procedure that makes it possible to alter the time pattern of electricity usage.

(18) **Energy Service-**The specific need that is served by the final use of energy, such as lighting, cooking, space heating, air conditioning, refrigeration, water heating or motive power.

(19) **Implementation Period**-The time interval between the filings required of each utility pursuant to 4 CSR 240-22.080.

(20) **Implementation Plan-** Descriptions and schedules for the major tasks necessary to implement the preferred resource plan over the implementation period.

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

(22) **Levelized Cost-**The dollar amount of a fixed annual payment for which a stream of those payments over a specified period of time is equal to a specified present value based on a specified rate of interest.
(23) **Load Impact-**The change in energy usage and the change in diversified demand during a specified interval of time due to the implementation of a demand-side measure or program.
(24) **Load Profile**-A plot of hourly demand versus chronological hour of the day from the hour ending 1:00 a.m. to the hour ending 12:00 midnight.
(25) **Nominal Dollars-**Future or then-current dollar values that are not adjusted to remove the effects of anticipated inflation.
(26) **Participant**-A customer who implements one (1) or more end-use measures as a direct result of a demand-side program.
(27) **Planning horizon-**A future time period of at least twenty (20) years' duration over which the costs and benefits of alternative resource plans are evaluated.
(28) **Pre-integration Filing-**The filing made by the Utility to report the results of its analysis from 4 CSR 240-22.030 (Load Analysis and Forecasting), 4 CSR 240-22.040 (Supply-Side Resource Analysis) and 4 CSR 240-22.050 (Demand-Side Resource Analysis).
(29) **Preferred Resource Plan-**The resource plan that is contained in the resource acquisition strategy that has most recently been adopted for implementation by the electric utility.
(30) **Probable Environmental Cost-**The expected cost to the utility of complying with new or additional environmental laws, regulations, taxes or other requirements that the Utility judges may be imposed within the planning horizon and could have a significant impact on utility rates.
(31) **Program Administrator Cost (PAC) Test-**A test of the cost-effectiveness of demand-side programs that compares the avoided utility costs to the sum of all utility incentive payments, plus utility costs to administer, deliver and evaluate each demand-side program to quantify the net savings obtained by substituting the demand-side program for supply resources.
(32) **Resource Acquisition Strategy-**A preferred resource plan, an implementation plan and a set of contingency options for responding to events or circumstances that would render the preferred plan obsolete.
(33) **Resource Plan-**A particular combination of demand-side and supply-side resources to be acquired according to a specified schedule over the planning horizon.
(34) **Resource Planning-**The process by which an electric utility evaluates and chooses the appropriate mix and schedule of supply-side and demand-side resource additions to provide customers with an adequate level, quality and variety of energy services.
(35) **Subjective Probability-**The judgmental likelihood that the outcome represented by each branch of a Chance Node will actually occur.
(36) **Supply-side resource**-Any device or method by which the electric utility can provide to its customers an adequate level of electric power supply.
(37) **Total Resource Cost Test (TRC)-**A test of the cost-effectiveness of demand-side programs that compares the sum of avoided utility costs plus avoided probable environmental costs to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver and evaluate each demand-side program to quantify the net savings obtained by substituting the demand-side program for supply resources.
(38) **Uncertain Factor-**An event, circumstance, situation, relationship, causal linkage, price, cost, value, response or other relevant quantity which can materially affect the outcome of resource planning decisions, about which the Utility has incomplete or inadequate information at the time a decision must be made.
(39) **Utility Costs-**The costs of operating the utility system and developing and implementing a resource plan that are incurred by the utility.
(40) **Utility Discount Rate-**The post-tax rate of return on net investment used to calculate the utility's annual revenue requirements.

4 CSR 240-22.030 Load Analysis and Forecasting
(1) The utility shall develop and maintain data on the actual historical patterns of energy usage within its service territory. The following information shall be maintained and updated on an ongoing basis:
(A) The historical database shall be maintained for each of the major customer classes.
(B) The historical database shall contain the following data:
1. For each jurisdiction under which the utility has rates established and for which it prepares customer and energy forecasts, and for each major class, actual monthly energy usage and number of customers and weather-normalized monthly energy usage;

2. For each major class, estimated actual and weather-normalized demands at the time of monthly system peaks; and
3. For the system, actual and weather-normalized hourly net system load.

(C) The historical database shall contain for each jurisdiction under which the utility has rates established and for which it prepares customer and energy forecasts, and for each major class, total monthly energy and demand savings from the utility's implemented demand-side programs.

(D) For each major class or subclass, the utility shall archive previous 4 CSR 240-22.030 base case forecasts and provide a comparison of the historical forecasts to the current base case forecasts.

(E) The utility shall retain the historical database for the ten most recent years.

(2) The utility shall develop a consistent set of hourly load profiles for the most recent year for which data is available.

(A) Load profiles shall be developed for each major class and for the net system load.

(B) The estimated major class load profiles shall be calibrated to sum to the net system load profiles.

(3) The utility shall develop a range of forecasts of the amount of energy and demand consumers will need over the planning horizon. It shall develop forecasts for multiple scenarios that are necessary or appropriate in the development of its integrated resource plan. Among the scenarios are the base case scenario (a scenario based on the most likely assumptions), a high-growth scenario, and a low-growth scenario. Subjective probabilities shall be assigned to each of the load forecast cases. The utility shall provide a description of how the forecast scenarios and associated subjective probabilities were determined.

(4) Each forecast shall identify the significant demand and use determinants; describe the data, the sources of the data, the assumptions and the analysis upon which the forecast is based; indicate the relative sensitivity of the forecast result to changes in assumptions and varying conditions; and describe the procedures, methodologies, and models used in the forecast, together with the rationale underlying the use of such procedures, methodologies, and models.

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

(6) The utility shall use reasonable methodologies in forecasting, including, where deemed appropriate by the Utility, a disaggregated end use methodology, preferably with primary market research data.

4 CSR 240-22.040 Supply-Side Resource Analysis

(1) The analysis of supply-side resources shall begin with the identification of a variety of potential supply-side resource options which the utility can reasonably expect to develop and implement. These options include new plants using existing generation technologies; new plants using new generation technologies; life extension and refurbishment at existing generating plants; purchased power from utility sources, cogenerators or independent power producers; efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information for each of these potential resource options which shall include at least the following attributes where applicable:

(A) Fuel type and feasible variations in fuel type or quality;
(B) Fuel transportation and shipping;
(C) Practical size range;
(D) Maturity of the technology;
(E) Lead time for permitting, design, construction, testing and startup;
(F) Capital cost per kilowatt;
(G) Annual fixed operation and maintenance costs;
(H) Annual variable operation and maintenance costs;
(I) Scheduled routine maintenance outage requirements;
(J) Equivalent forced-outage rates or full- and partial-forced-outage rates;
(K) Operational characteristics and constraints of significance in the screening process;
(L) Environmental impacts, including at least the following:

1. Air emissions including at least the primary acid gases, greenhouse gases, ozone precursors, particulates and air toxics;
2. Waste generation including at least the primary forms of solid, liquid, radioactive and hazardous wastes;

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

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

(M) Transmission costs; and

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

(2) Each of the supply-side resource options referred to in section (1) shall be subjected to a screening analysis. All costs shall be expressed in nominal dollars.

(A) Cost rankings shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the resource using the Utility Discount Rate.

(B) The Probable Environmental Cost of each supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental laws or regulations that may be imposed at some point within the planning horizon. The utility shall provide a description of how the alternative mitigation levels and associated subjective probabilities were determined.

(C) The utility shall indicate which Supply-side Options are considered to be CandidateResource Options for purposes of developing the Alternative Resource Plans. The utility shall also indicate which Resource Options are eliminated from further consideration and shall explain the reasons for their elimination.

(3) Before developing alternative resource plans and performing the integrated resource analysis, the utility shall develop ranges of values and subjective probabilities for several uncertain factors related to candidate supply resources. The utility shall provide a description of how the ranges and subjective probabilities were determined. These cost estimates shall include at least the following elements:

(A) Fuel price forecasts over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical. Transportation and shipping costs to deliver the fuel shall be included in the price forecasts.

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

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

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

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

4 CSR 240-22.050 Demand-Side Resource Analysis

(1) The utility shall provide energy-efficiency and demand response potential supply curves, which clearly show the incremental cost (in dollars per kWh and dollars per kw) of increasing demand-side related load reductions over the 20-year planning horizon. Demand-side portfolios with increasing amounts of load reductions, both kW and kWh, shall be passed to integration analysis until such time that the demand-side portfolio is not the least cost resource option. After having calculated this breakeven point, the utility shall then assess whether to include this demand-side portfolio in their preferred plans or include an alternative demand-side portfolio. If a utility chooses an alternative demand-side portfolio, the utility shall explain the reasons for its decisions.

(2) When analyzing demand-side measures and developing demand-side programs, the utility shall determine the following:

(A) The Total Resource Cost test is the primary indicator of demand-side program cost effectiveness.

(B) Demand-side programs must also pass the Program Administrator Cost (PAC) test of cost-effectiveness. Under the PAC test, the program benefits are the same as the TRC test, but costs are defined more narrowly to just include the costs incurred by the program administrator, and not the participating customer.

(C) The utility shall describe the method and rationale in developing avoided costs.

(D) In addition, the utility shall describe the method for (1) grouping hours into avoided cost periods to reflect significant differences in the seasonal and/or hourly variation in prices, and (2) for allocating capacity costs to these periods.

(E) For candidate demand-side programs, the utility shall provide the following information for each resource:

1. the type of resource (demand response or energy efficiency);

2. the capacity and energy available in the program;
3. annualized costs; number of customers projected to be enrolled in each program;
4. the number of times the utility expects to call upon the demand response resource;
5. where applicable, the capacity reduction expected; and,
6. the utility shall also list any demand-side resource it has discontinued.

(F) The utility shall also indicate which demand-side programs are eliminated from further consideration and shall explain the reasons for their elimination.

(G) For programs that may be impacted by Regional Transmission Organization (RTO) rules, the utility shall describe the specific RTO rule and the impact that it may have on either program development or program rejection.

(3) The utility shall evaluate distributed generation technologies on an equivalent basis as other end-use measures. Distributed generation technologies that pass the cost-effectiveness screening shall be included as a candidate demand-side program.

(4) Utilities shall evaluate statewide marketing and outreach programs, upstream market transformation programs and other activities in their proposed portfolios designed to support 4 CSR 240-22.010. In the event statewide marketing and outreach programs are preferred, utilities shall work with the Missouri Department of Natural Resources to develop such programs.

4 CSR 240-22.060 Integrated Resource Analysis

(1) The utility shall use appropriate combinations of candidate demand-side and supply-side resources to develop a set of alternative resource plans to satisfy at least the objectives and priorities identified in 4 CSR 240-22.010.The utility shall provide a description of each alternative resource plan, including the type and size of each resource addition and a listing of the sequence and schedule for retiring existing resources and acquiring each new resource addition

(2) The utility shall specify a set of quantitative measures for assessing the performance of alternative resource plans with respect to identified planning objectives. All present value and levelization calculations shall use the utility discount rate and all costs and benefits shall be expressed in nominal dollars.

(3) The utility shall assess the relative performance of the alternative resource plans by calculating for each plan the value of each performance measure. The analysis shall be carried out with computer models that are capable of simulating the total operation of the system on a year-by-year basis in order to assess the cumulative impacts of alternative resource plans. The utility shall indicate which alternative resource plans are considered to be candidate resource plans for purposes of 4 CSR 240-22.070. The utility shall also indicate which plans are eliminated from further consideration on the basis of the screening analysis and shall explain the reasons for their elimination.

4 CSR 240-22.070 Risk Analysis and Strategy Selection

(1) The utility shall describe the methods used to assess the impacts of critical uncertain factors on the expected performance of each candidate resource plan, to analyze the risks associated with candidate resource plans, to evaluate circumstances which would cause the utility to select an alternate preferred plan and to explicitly state and document the subjective probabilities that the Utility assigns to each of these uncertain factors, taking into account the fundamental objective of the resource planning process provided for in 4 CSR 240-22.010.

(2) The utility shall identify and assess the relative impact of each candidate uncertain factor to determine which candidate uncertain factors are critical to the performance of the candidate resource plans. This analysis shall include at least the following candidate uncertain factors:

(A) The range of future load growth represented by the low-case and high-case load forecasts;
(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital;
(C) Future changes in environmental laws, regulations or standards;
(D) Fuel prices;
(E) Construction, including siting and permitting, schedules for new generation and transmission facilities;
(F) Construction, including siting and permitting, costs for new generation and transmission facilities;
(G) Long-term power purchases and/or sales availability, terms, and cost;
(H) Emission allowance prices;
(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;
(L) Costs for demand-side programs; and
(M) Any other uncertain factors that the utility determines may be critical to the performance of alternative resource plans;

(3) The utility shall select a preferred resource plan from among the candidate resource plans that, in the judgment of the Utility strikes an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010. The utility shall provide a discussion and documentation of the process used to select the preferred resource plan.

(4) The utility shall develop an implementation plan that specifies the major tasks and schedules necessary to implement the preferred resource plan over the Implementation Period. The implementation plan shall contain:
(A) A schedule and description of ongoing and planned research activities to update and improve the quality of data used in load analysis and load forecasting;
(B) A schedule and description of ongoing and planned demand-side programs and research activities;
(C) A description of the strategy for the impact evaluation plans for the demand-side programs that are included in the preferred resource plan; and the results of any such evaluations that have been completed since the Utility's last scheduled filing pursuant to 4 CSR 240-22.080;
(D) A schedule and description of major supply-side resource research, engineering, acquisition and construction activities related to the implementation period;
(E) Identification of major milestones for each resource acquisition project, including decision points for committing to major expenditures; and

(5) The utility shall develop, document, and officially adopt a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by the board of directors, a committee of senior management, an officer of the company or other responsible party who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:
(A) The Preferred Resource Plan;
(B) The Implementation Plan;
(C) A set of Contingency Plans and description of the process by which the Utility will determine if the Implementation Plan is judged inappropriate; and
(D) A description of the process the Utility will use to monitor the critical uncertain factors and report significant changes to the Utility managers or officers who have the responsibility of resource acquisition.

4 CSR 240-22.080 Filing Schedule and Requirements
(1) Each electric utility which sold more than one (1) million megawatt-hours to Missouri retail electric customers for calendar year 2008 shall make a full compliance filing with the Commission every three (3) years on September 1. The electric utilities shall submit a filing made in accordance with the requirements of 4 CSR 240-22 on the following schedule:
(A) Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company or its successors, on September 1 of 2012 and every third year thereafter;
(B) The Empire District Electric Company, or its successor, on September 1 of 2013 and every third year thereafter;
(C) Union Electric Company d/b/a AmerenUE, or its successor, on September 1 of 2014 and every third year thereafter.

(2) The utility's full compliance filing shall demonstrate compliance with the provisions of this chapter, and shall include at least the following items:
(A) Letter of transmittal;
(B) Executive Summary. Each utility shall prepare an Executive Summary, separately bound and suitable for distribution to the public, which shall be a non-technical description of the plan. This document shall summarize the contents of the Technical Volume(s). The summary shall include:
1. A brief introduction describing the utility, its existing facilities, purchase power arrangements, demand-side programs, and the purpose of the plan;
2. The base case forecast growth in peak demand and energy for the planning horizon, with and

without utility demand-side programs and a listing of the economic and demographic assumptions associated with each;

3. A summary of the Preferred Plan clearly showing the demand-side resources and supply-side resources contained in each.

4. A description of the major research projects and programs the utility will continue or commence during the implementation period, and the reasons for their selection;

5. Estimated impact on retail rates;

6. Estimated impact on the electric utility's credit metrics;

7. Identification of critical uncertain factors affecting the preferred plan; and

8. Such other information as the electric utility may determine appropriate, or the Commission shall require.

(C) Technical Volume(s). Each utility shall prepare Technical volume(s) which shall include the information required by 4 CSR 240-22.

(D) The highly confidential form of the capacity balance spreadsheet completed in the specified format;

(E) The Utility shall submit to the manager of the Commission Energy Department all of the supporting documentation as specified in 4 CSR 240-22.080 (11) used in the preparation of the full compliance filing. This information may be submitted to the manager of the Energy Department through the Commission's electronic filing and information system (EFIS).

(3) The utility shall work with representatives of public and private entities (to be generally referred to as the utility's "stakeholder group") in the development of its integrated resource plan. The public and private entities that may be included in the stakeholder group are those that represent interests not represented by the Staff and the Office of the Public Counsel and that are meaningfully affected by the utility's integrated resource plan and that can provide a significant perspective or significant useful expertise in the development of the plan; provided, that the stakeholder group should not include multiple entities whose interests are adequately represented by others in the group and should not become so large as to be inefficient or unwieldy. The utility shall consider the input of the stakeholder group; but the utility is not bound to follow the advice. The Commission's rules on confidentiality shall apply to all information provided to participants in the stakeholder process in the same manner and fashion as it would apply if the information were provided in a docketed case at the Commission.

(4) Prior to beginning the Integrated Resource Analysis required by 4 CSR 240-22.060, the utility shall make a pre-integration filing with the Commission which sets forth the utility's results from its load analysis and forecasting, supply-side resource analysis and demand-side resource analysis. The Commission staff shall review each pre-integration filing and shall file a report within sixty (60) days after the pre-integration filing was made which indicates the results of its review. The staff's report shall indicate all of the potential deficiencies or concerns that staff alleges exist with respect to the utility's pre-integration work. Within the same timeframe, the public counsel and any stakeholder group participant may also file a report indicating the potential deficiencies or concerns they allege exist. The utility shall review each report and make changes to its pre-integration work as it determines is appropriate.

(5) At least annually, each electric utility shall host an update workshop with the staff, public counsel, and the parties to the Utility's previous docket respecting its previous compliance filing. The purpose of the workshop shall be to update the participants regarding the Utility's implementation plan, the status of the identified critical uncertain factors, and changing conditions that are impacting or are reasonably expected to impact the Implementation Plan.

(6) The Commission shall establish a docket for the purpose of receiving the pre-integration and compliance filings of each Utility. The Commission shall issue an order that establishes an intervention deadline and provide for notice.

(7) The staff shall review each compliance filing required by this rule and shall file a report not later than ninety (90) days after each Utility's scheduled filing date. The staff's report shall identify any deficiencies or concerns that the staff alleges exist with regard to the compliance filing. If the staff's review finds no deficiencies or 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) Within ninety (90) days after a Utility's compliance filing, the public counsel and any intervenor may file a report or comments. The report or comments may identify any deficiencies or concerns that such parties allege exist with regard to the compliance filing.

(9) If the staff, public counsel or any intervenor identifies an alleged Deficiency or Concern respecting any part of the compliance filing that deals with any portion of the pre-integration work conducted by the utility that was not identified in its report on the utility's pre-integration filing, it shall be clearly identified as new, and such party shall provide a complete explanation of why it was not identified in their pre-integration report. For each alleged Deficiency, the staff, public counsel and any intervenor shall provide supporting evidence that compliance with the Commission's rule would have caused the Utility to select an alternative resource plan as the Utility's preferred resource plan. Also, for each alleged Deficiency, each party shall provide at least one suggestion for how the deficiency or concern could be remedied. 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 alleged Deficiency or Concern shall be submitted to all parties within five (5) days of filing the report or comments.

(10) If the staff, public counsel, or any intervenor alleges that a Deficiency or Deficiencies exist, they shall work with the 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 alleged Deficiencies. If full agreement cannot be reached, this shall be reported to the Commission through a joint filing as soon as possible, but no later than fifty (50) days after the date on which the report or comments were submitted. The joint filing shall set out in a brief narrative description those areas on which agreement cannot be reached.

(11) If full agreement on remedying alleged Deficiencies is not reached, then within sixty (60) days from the date on which the staff, public counsel, and any intervenor submitted a report or comments relating to the Utility's compliance filing, the Utility may file a response and the staff, public counsel, and any intervenor may file comments in response to each other. The Utility response shall indicate whether or not it agrees that there is one or more Deficiencies in its compliance filing and shall also address any Concerns set forth by staff, public counsel or any intervenor.

(12) If full agreement is not reached on remedying all alleged Deficiencies, the Commission shall:

(A) Issue an order which indicates on which alleged Deficiencies, if any, a hearing will be held, and which establishes a procedural schedule if the Commission has elected to hold a hearing;

(B) With or without holding a hearing, issue an order which acknowledges or declines to acknowledge the utility's integrated resource plan; and

(C) The Commission may elect to indicate its agreement or disagreement with any unresolved Concerns of the staff, the public counsel or any intervenor.

(D) The Utility shall resolve Deficiencies with which it agrees according to the terms of the agreed-upon remedies for such Deficiencies. If the Commission chooses not to acknowledge the utility's integrated resource plan, the Commission may order the utility to resolve other Deficiencies that it determines exist within a reasonable period of time.

(13) 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 Utility's or its contractors' possession, custody or control shall be preserved and submitted within five (5) days of its compliance and pre-integration filing to the staff, public counsel, and any intervenor for use in its review of the periodic filings required by this rule. Each 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) full compliance filings.

(14) If the Utility determines that circumstances have changed so that the Implementation Plan is no longer appropriate, the Utility, shall notify the Commission in writing within sixty (60) days of the Utility's determination. The written notification shall include a description of all changes, the impact of each change and all other performance measures specified in the last compliance filing. If the Utility decides to implement a Contingency Option, the Utility shall file for review in advance of its next regularly scheduled Compliance Filing a revised Implementation Plan.

(15) If the Utility requires additional regulatory certainty to implement the Resource Acquisition Strategy then the Utility may request the Commission to open a new docket to for purposes of seeking pre-approval of the Utility's Resource Acquisition Strategy or any sub-component thereof.

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

(A) The granting of a variance to one (1) 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 Utility with a provision of these rules.

(B) The Commission may waive or grant a variance from this chapter in total.

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