

## 2. Planning Scenarios

### Highlights

- *Ameren Missouri worked with Charles River Associates to define and model ten planning scenarios.*
- *The planning scenarios are defined by a probability tree which is comprised of three uncertain factors: carbon policy, natural gas prices, and load growth.*
- *The three uncertain factors are dependent in that they have interactive effects. They are also considered to be critical, as different values could sway resource selection.*
- *For each of the three critical dependent uncertain factors, subjective probability distributions were identified by subject matter experts using formal decision analysis techniques.*

Ameren Missouri consulted Charles River Associates (CRA) to help determine the critical factors that should define the planning scenarios, elicit subjective probabilities from Ameren Missouri experts about those variables, and then model those scenarios with their integrated environmental and economic model. Based on prior modeling experience, three interactive variables were chosen to define scenarios and are expected to have the largest impact on future resource choices: carbon policy, natural gas prices, and load growth. Based on the outcomes of the expert interviews, Ameren Missouri adopted 10 scenarios to represent the uncertainty of the three critical variables. CRA modeled each scenario to provide the necessary internally-consistent inputs for further IRP analysis. The load forecasts for Ameren Missouri, as seen in Chapter 3, were developed to be consistent with the same uncertainty expected by internal experts and on which the planning scenarios were based. Chapter 9, Modeling and Risk Analysis, discusses the details of how the scenarios were used to judge the performance of alternative resource plans as well as the results of further sensitivity analysis of additional uncertain factors.

### 2.1 Scenarios and the Probability Tree

The building and analysis of several “scenarios” of key future market outcomes for national-scale variables is the starting point for the evaluation of resource plans, and the first step of the risk analysis. These scenarios make up a “probability tree,” meaning that each scenario has a probability associated with it, and that the scenarios as a group were developed to span a full probable range of relevant market outcomes. The probability tree is developed to describe multiple combinations of critical uncertain factors that have interrelated (or “dependent”) impacts on projections of multiple energy and environmental variables. The “critical” variables comprising the probability tree are

those for which reasonably likely alternative forecasts could significantly sway the evaluation of candidate resource plans.

For each scenario in the probability tree, Ameren Missouri must have “integrated” sets of forecasts of the “nationally-defined” inputs to IRP calculations of resource plan revenue requirements. In this context, the term “integrated” denotes that all of the individual variable projections for a particular scenario are mutually consistent with one another, which requires a model with the ability to simultaneously simulate interactions in fuel and energy markets, electricity generation system operation, non-electricity sector outcomes, macroeconomic activity levels, and sector-specific responses to emissions limits.

The term “nationally-defined” denotes that the projected outcome is determined by supply and demand events that occur on a scale larger than that of Ameren Missouri or its territory, and would apply to such variables as U.S. electricity demand. Charles River Associates’ (CRA’s) MRN-NEEM model, a computable general equilibrium representation of the full U.S. economy integrated with a dispatch model of individual electricity generating units, satisfies both of the above criteria. By simulating each scenario as an MRN-NEEM model run, Ameren Missouri can produce integrated, nationally-defined projections of the inputs to the detailed, system-level IRP evaluations.

In the Sensitivity Analysis step of the IRP risk analysis, other uncertain variables are evaluated and the critical independent uncertain factors are identified and then added to the scenario probability tree. As the name implies, independent uncertain factors are those whose impacts on multiple energy and environmental projections are not regarded as interrelated. This topic is discussed in detail in Chapter 9.

## 2.2 Critical Dependent Uncertain Factors

To determine which variables should comprise the probability tree and to determine the associated probabilities, Ameren Missouri consulted the firm Charles River Associates (CRA) to assist. Although Ameren Missouri developed a list of 22 candidate uncertain factors, as seen in Table 2.1,<sup>1</sup> the relevant variables for this step are those which are subject to a range of uncertainty within which different values might significantly sway the evaluation of

**Table 2.11 Candidate Uncertain Factors**

|                    |                                       |
|--------------------|---------------------------------------|
| Load Growth        | DSM Cost                              |
| Interest Rates     | Off-System Sales                      |
| Carbon Policy      | Investment Tax Credit                 |
| Fuel Prices        | Variable O&M                          |
| Project Cost       | Return on Equity                      |
| Project Schedule   | Hourly Price Shapes                   |
| Purchased Power    | Power Price Volatility                |
| Emissions Prices   | Nuclear Incentives                    |
| Fixed O&M          | Wind Capacity Factor                  |
| Forced Outage Rate | Solar Capacity Factor                 |
| DSM Load Impacts   | Transmission<br>Interconnection Costs |

<sup>1</sup> 4 CSR 240-22.070(2); 4 CSR 240-22.070(11)(A)2.;

resource plans (i.e., can be critical to the resource plan decision), and that are nationally-defined in scope. Identifying individual variables rather than complex packages of multiple variable outcomes facilitates the expert elicitation process described in the next section of this chapter. The various combinations of these critical, nationally-defined variables, and their associated likelihoods, will form the scenarios represented in the final probability tree. Each of these scenarios will be analyzed as an MRN-NEEM model run, which will produce internally-consistent, integrated projections of key IRP inputs to the standard Ameren Missouri system-level analysis of resource plans.

Following a review of the results and assumptions from previous analysis between Ameren Missouri and CRA, including that performed for Ameren Missouri's 2008 IRP, it was determined that the appropriate variables for probability elicitation were: load growth, carbon policy, and natural gas prices.

Four other variables were also considered to be potential components of the scenario probability tree<sup>2</sup>. It was determined that the IRP decisions would not be as sensitive to these three variables for the reasons explained below:

- Gross Domestic Product (GDP) – It was determined that uncertainty in this variable would affect IRP outcomes primarily in the way it would affect other critical variables, particularly electricity demand growth and natural gas prices, and thus the IRP-relevant aspects of GDP uncertainty could be folded into the latter two uncertainty representations;
- Lower coal prices – Lower coal commodity prices would tend to be offset by carbon prices under a world with a carbon cap, which we expected would play a high-probability role in the IRP tree. Also, because Ameren Missouri is not modeling new uncontrolled coal as a resource option, the range of uncertainty expected in coal prices is unlikely to substantially affect the choice among the non-coal IRP alternatives;
- Construction costs – Although this variable is expected to influence resource selection it was evaluated as an independent uncertainty in the risk analysis. Construction costs do not have strong interrelated effects compared to the other variables being considered;
- 3-P Emission Prices<sup>3</sup> – Modeling results indicate that, unlike for carbon, wide variations in “3-P” (mercury, SO<sub>2</sub>, NO<sub>x</sub>) emissions prices have very little impact on IRP-relevant inputs and outputs. The determination to exclude variations in 3-

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<sup>2</sup> EO-2007-0409 – Stipulation and Agreement #35; 4 CSR 240-22.070(2)

<sup>3</sup> 4 CSR 240-22.040(8)(D)2.

P policy from the scenario tree was based upon sensitivity analysis conducted for Ameren Missouri's 2008 IRP, in which variations in CAIR and CAMR caps produced insignificant changes to critical IRP drivers. At the time when CRA and Ameren Missouri discussed what variables should be included in the scenario tree both CAIR and CAMR had been remanded, and the form of any replacement legislation was very unclear. For mercury, the political backdrop was gravitating strongly towards a MACT approach and away from cap-and-trade, so the decision was to institute a two-phase mercury reduction requirement (the move to MACT also meant that there was no longer going to be an allowance price for Mercury). However, lacking a specific legislative alternative to CAIR, the CAIR SO<sub>2</sub> and NO<sub>x</sub> caps were simulated as originally written. After the MRN-NEEM analysis was completed, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, with more stringent caps. Simultaneously, momentum has gathered behind SO<sub>2</sub> and NO<sub>x</sub> MACT requirements triggered by new hazardous air pollutant (HAP) rules. CATR would likely produce higher SO<sub>2</sub> and NO<sub>x</sub> allowance prices, but any resulting impacts on critical IRP drivers would not be more influential than the impacts caused by carbon policy, natural gas prices, and load growth. In addition, if CATR were to be paired with MACT requirements for both SO<sub>2</sub> and NO<sub>x</sub>, then allowance prices for SO<sub>2</sub> and NO<sub>x</sub> might be elevated for one or two years, but would then collapse as all units would be required to add controls thereby making the caps non-binding. Later in the risk analysis Ameren Missouri evaluated more stringent environmental regulations to model the effects on existing plants and the resultant impact on resource needs.

### 2.3 Assigning Subjective Probabilities

The appropriate individual to assign subjective probabilities is the decision-maker or the person(s) that the decision-maker designates as the best expert(s). Ameren Missouri's management identified several in-house experts to provide the probability distributions for each critical dependent uncertain variable. (Later, senior Ameren Missouri management (the decision-maker) reviewed the resulting subjective probabilities and their basis, and approved them for use in the IRP risk analysis).

CRA structured each probability elicitation session following key principles of sound probability encoding techniques. The process had the following structure.

- First, the purpose of the elicitation process – to minimize natural cognitive biases – was explained, as was the planned use in the IRP of information that would be the subject of the interview. Potential areas of motivational bias were also explored before starting each elicitation. (CRA did not detect any concerns in this regard.)

- Next, the variable to be encoded was defined. The interviewer encouraged the expert to describe events and contingencies that would affect his expectations about the outcome of the uncertain variable. If it became apparent that the expert found that the full uncertainty was too complex to analyze as a whole, the interviewer broke it down into a set of simpler constituent parts, following the structure described by the expert. The formal elicitation was then performed on the various contingent variables. (After the completion of the elicitation, CRA reconstructed the overall probability distribution from the contingent elements and their respective probabilities.)
- Third, the interviewer had the expert identify the specific units for each variable to be encoded, conducted a sequence of “conditioning” questions intended to lessen some common sources of cognitive biases, and used a variety of probability elicitation techniques to obtain quantitative statements that, as a group, described the expert’s subjective views on the probability distribution for each variable in question.
- At the conclusion of each interview, CRA showed the expert the produced probability distributions and recapped the experts’ general thinking that explained the ranges, areas of likelihood, and contingencies. In each case, CRA verified that these were representative of the expert’s beliefs before completing the interview.

There were two experts assigned to each variable. Each was interviewed separately. Such multi-expert elicitations invariably result in different views; indeed, the ability to observe these differences of views is one of the benefits of soliciting information separately from more than one expert. After both had been interviewed, CRA summarized the responses of the two into a comparative format, which was then presented in a conference call to the two individuals together.

Where differences were most pronounced, CRA used the statements from the interviews to highlight what seemed to be the differences in information or perspectives explaining the differences. Discussion of these differences was encouraged, following which the experts were given the opportunity to amend their views in light of the additional discussion. CRA also provided a probability distribution that combined their separate views using equal weights, which could be used in the IRP process, once each expert was fully satisfied with his own individual probability distribution. In this way, CRA developed a single probabilistic statement of potential outcomes for each of the three critical variables that Ameren Missouri’s in-house experts agreed was a fair representation of their individual sense of the uncertainty, and the range of opinions across the experts within Ameren. The details and results of those elicitations can be found in Chapter 2 – Appendix A.

## 2.4 Probability Tree Trimming

A probability tree is created by combining discretized summaries of multiple uncertain variables. Each individual branch, or case, reflects the expected value for a range of values of a continuous variable, and its probability reflects the cumulative probability associated with that range.

In the context of this analysis, there were three variables chosen for inclusion in the probability tree. This implies that the minimum tree size is 8 scenarios/endpoints; that is, 2 natural gas price branches times 2 load branches times 2 carbon policy branches.

However, the complexity of carbon policy outcomes detailed in the elicitation discussion (see Chapter 2 - Appendix A) implies, at minimum, a 17 scenario tree (and this is only after collapsing the high and low load and gas price cases into average branches for the BAU scenario).

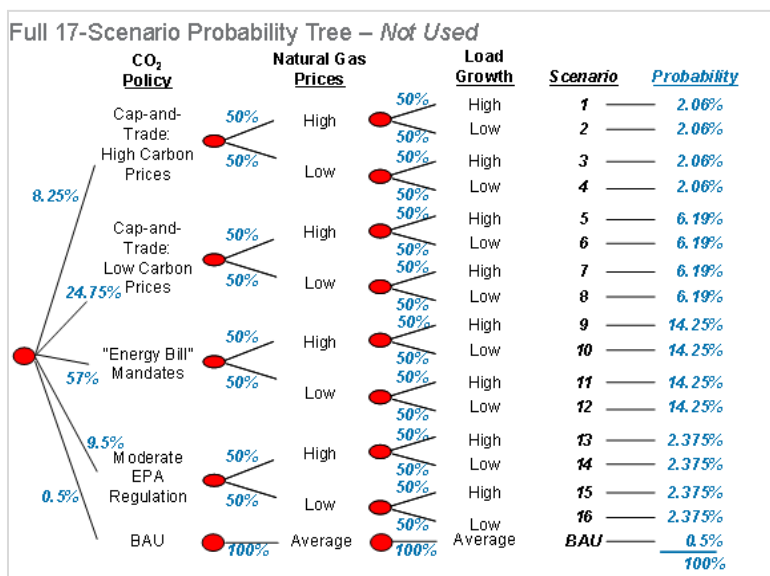
That 17-branch structure is illustrated in Figure 2.1. Half of the scenarios in such a tree would be allocated less than a 2.5% probability: scenarios 1 through 4 each having a 2.06% probability, scenarios 13 through 17 each having a 2.375% probability, and the BAU (Business As Usual) scenario having a 0.5% probability.

In any IRP, the maximum number of integrated modeling scenarios feasible given time and financial resource limitations must guide how many branches per variable are desirable. It is possible (although not always optimal), to create more branches for some variables (e.g., carbon policy) than for others, depending upon the relative ranges in each expert's CDF (cumulative distribution function), how asymmetric

each variable's CDF is, and the sensitivity of each variable on IRP decision criteria (e.g., the present value of revenue requirements). In general, branches with a very small probability should be avoided, except if a low probability outcome range exists that would have exceptionally large impacts on decision criteria outcomes.

In recognition of the modeling resources required of each MRN-NEEM scenario, Ameren Missouri considered the trade-off of decreases in the number of total branches

**Figure 2.41 Untrimmed Probability Tree**

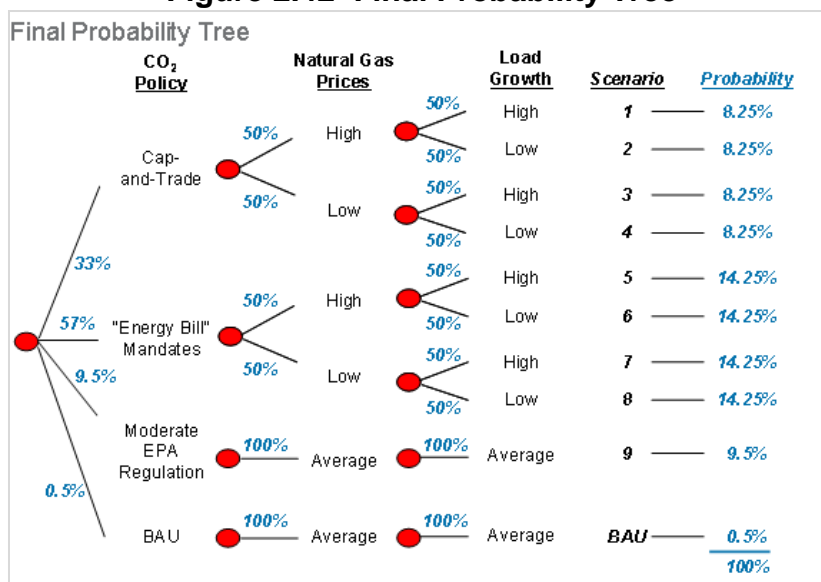


in the tree against the loss in variance that such trimming would imply. The lowest probability branches in the 17-branch tree were a result of having two distinct carbon price pathways. Ameren Missouri decided to collapse these two branches into a single expected value path for carbon price outcomes.

The loss in representation of a wider range in potential carbon price outcomes was deemed acceptable given that it allowed a substantial 23% reduction in tree size (in terms of the number of MRN-NEEM scenarios). The branches associated with Moderate EPA Regulation also represented very small slivers of the overall probability.

All of the different combinations that included EPA regulation were combined into a single branch to create a tree with nine branches and the BAU. Ameren Missouri deemed this a reasonable way to trim the tree as this carbon policy outcome has relatively low probability (9.5%), so the loss in variance by treating it as a single branch in the total tree is small if it is simply analyzed in combination with average natural gas prices and average load growth. The final trimmed probability tree depicted in Figure 2.2 has 10 scenarios, each of which has a balanced share of overall probability.<sup>4</sup>

**Figure 2.42 Final Probability Tree**



## 2.5 Scenario Modeling

### 2.5.1 Top-Down & Bottom-Up Models

CRA<sup>5</sup> uses an integration of two distinct classes of models to simulate the market dynamics of the electricity sector within the broader U.S. economy: (1) a general

<sup>4</sup> 4 CSR 240-22.070(1); 4 CSR 240-22.070(2); 4 CSR 240-22.070(3); 4 CSR 240-22.070(4)

<sup>5</sup> 4 CSR 240-22.040(8)(D)1.; 4 CSR 240-22.040(8)(A)1.

equilibrium (or top-down) model and (2) an investment and technology decision-based linear programming (or bottom-up) model. These classes of models, in general, are analyzed by employing two distinct modeling paradigms: top-down and bottom-up analysis.

The top-down models are the standard economic framework for analyzing economy-wide policies and are the most commonly used tool for assessing macroeconomic impacts. In this modeling framework, an economy, including production sectors, final household demand, and government taxation and spending, is completely represented, so as to capture economy-wide relationships.

But most importantly, the model is based on rigorous microeconomic theoretical foundations. Under carbon policy scenarios, all agents in the model respond to price changes, including changes in energy prices and products that utilize energy in their manufacture. The inter-linkages within the model enable it to take into account a complete set of feedbacks within the economy.

The top-down models can also be easily expanded to include multiple regions linked by trade. With such flexibilities, top-down models are suitable for simulating a wide variety of policies, such as the impact of energy policies, trade policies, public finance policies, and many other real world policies, to determine who wins and who loses. The MRN model falls under this category.

Bottom-up models, on the other hand, are used to find the choice of least-cost technology that satisfies a portfolio of policy measures. These models involve a detailed characterization of one aspect of the economy. In particular, models of the electricity sector constructed at the unit level with a menu of costs for current and future technologies are often employed to study the impact of environmental policies on this sector. The NEEM model falls under this bottom-up category.

The two approaches are very distinct in both model structure and their representation of the energy-economic system. The top-down model's representation of the economy is complete at a macro-level but lacks detail regarding specific technologies. Specific technologies are best described from an engineering perspective, which general equilibrium models are unable to represent.

In the top-down model, an economic system is represented by production sectors where preferences and technologies are represented by smooth functions. All agents in the model interact to capture economy-wide effects, and are forward-looking, rational optimizers. In contrast, the bottom-up model represents only a portion of the economy (e.g., the energy system or the electricity sector).

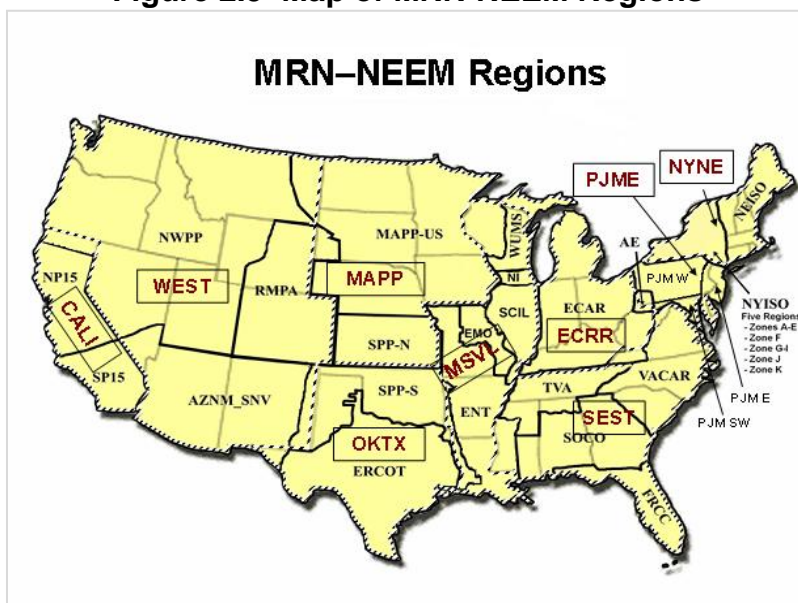
The bottom-up model has its limitations but they are compensated by the richness of its technology representation. In addition, bottom-up models like NEEM can encompass each and every generation unit within the electric sector, which adds realism to actual simulation for practical application. Despite these strengths, bottom-up models do not fully represent the economy and fail to account for macroeconomic feedbacks from the rest of the economy. Thus, bottom-up models cannot be used alone for macroeconomic analysis.

The effects of an economy-wide policy such as the proposed CO<sub>2</sub> branches represented in the probability tree ripple through the entire economy, so serious consideration of such a carbon policy requires macroeconomic analysis. At the same time, carbon policy will pointedly affect the electric sector, so the use of a bottom-up model is desirable. Therefore, top-down and bottom-up models have a complementary role to play in policy analysis. If coupled appropriately, they can generate a wide-range of detailed results that are consistent across the two models.

The weakness of the top-down model is well compensated by the strength of the bottom-up model and vice versa. Hence, integrating a top-down and a bottom-up model provides the best of both frameworks. CRA mathematically integrated its two models, MRN and NEEM, into a single MRN-NEEM model to provide a unique and consistent approach for U.S. economy-wide policy analysis.

An overarching difference between the two models is regional detail and definition. Figure 2.3 and Table 2.2 show the relationship between the NEEM and MRN regions. There are 29 U.S. NEEM regions but only 9 MRN regions.

**Figure 2.5 Map of MRN-NEEM Regions**



**Table 2.5 State Composition of MRN and NEEM Regions**

| MRN Region | States  | NEEM Region  |
|------------|---|--|
| ECRR       | MI, IN, OH, KY, WV                                | ECAR   |
| NYNE       | MA, ME, NH, NY, RI, VT, CT                        | NEISO, 5 NYISO Regions<br>(Upstate, Downstate, Capital, NYC, LIPA) |
| MAPP       | ND, SD, NE, KS, MN, IA                            | MAPP-US, SPP-N   |
| PJME       | PA, MD, DC, NJ, DE                                | AE, PJM  |
| CALI       | CA  | NP15, SP15   |
| WEST       | WA, OR, AK, HI, ID, MT, NV, UT, CO,<br>WY, AZ, NM | NWPP, RMPA, AZNM, SNV  |
| SEST       | MS, AL, TN, GA, SC, VA, NC, FL                    | SOCO, FRCC, TVA, VACAR   |
| OKTX       | TX, OK  | SPP-S, ERCOT   |
| MSVL       | IL, MO, AR, LA, WI                                | WUMS, NI, SCIL, EMO, ENT   |

### 2.5.2 Top-Down Modeling: MRN Model

MRN (Multi-Region Model) is a top-down, computable general equilibrium (CGE) model of region-specific impacts and regional interaction in the U.S. economy. The CGE tracks every dollar that is spent through the economy (to reduce carbon emissions, for instance), accounting for the economic gains in those sectors that provide the goods and services that result in emissions reductions, as well as the economic costs to those that incur added expenditures. In addition, the negative impacts associated with declining demand under higher, policy-induced prices are captured. The model also accounts for any changes in the distribution of wealth that result from the combined impact of emissions control spending and the disposition of newly created allowances. The results of a model run thus reflect the net impact to the U.S. economy after all the impacts on the winners and losers under a proposed policy have been estimated.

The model also assumes that implementation of a policy such as a carbon emissions cap will occur in a least-cost fashion with fully-functional, competitive product and allowance markets. The only limits imposed on the efficiency of a cap-and-trade market are those that are directly specified in a policy or bill, such as when some sectors are not covered by the proposed cap scheme (even if placed in the offsets category). Leakage of some economic activities outside of the U.S. is also estimated for sectors that face competitors in other countries that do not have their own emissions caps (or have weaker caps).

The model works with perfect foresight of future prices and policy requirements. This means that the model does not include any costs due to uncertainty and “surprises” that will probably also be associated with compliance with a new policy. It also captures only a long-run equilibrium in all of the markets, and thus does not include any of the costs of an overly rapid shift in markets due to the imposition of a new policy.

The CGE model solves for production levels, trade, relative prices, income, and consumption by accounting for technological as well as behavioral responses to changes in policy. The equilibrium is fully dynamic, meaning that investment decisions determine the future capital stock, which in turn determines future income and

consumption. Furthermore, decisions to consume or invest are taken with correct expectations about future policy and opportunities (i.e., with perfect foresight). Investment today requires foregoing consumption of current income. Consumer decisions maximize utility inter-temporally, which implies that an optimal financial trade-off is made between consumption today and consumption in the future.

Many of the impacts of policies to reduce carbon emissions indirectly increase the cost of production and consumption, and this has effects on the demand for all commodities. For example, a limit on the quantity of allowable emissions from electric utilities will result in higher electricity prices. Higher electricity prices will then raise production costs throughout the economy, but especially in sectors that use electricity-intensive production processes. As all sectors adjust their production processes to be optimized under post-policy prices, there are changes in demand for labor, materials and commodities, capital, and different types of fuels and primary energy sources. MRN only explicitly models the economy and energy sector in the U.S., but it does also account for foreign imports and exports. Data that characterize the interrelationships of commodity uses within the economy therefore are of primary importance in quantifying the impacts from alternative carbon regulations.

As a starting point for characterizing the inputs and outputs of commodities in the U.S. economy, MRN uses a Social Accounting Matrix (SAM) developed for each state by the Minnesota IMPLAN Group, Inc. (MIG). The IMPLAN database represents the activities in 509 sectors for all 50 states and the District of Columbia. CRA adjusts the original SAM data to be consistent with state level energy data from the U.S. Energy Information Administration (EIA), which are more accurate than the corresponding IMPLAN data with respect to energy flows in the U.S. economy. The SAM that results from the combination of IMPLAN and EIA data exactly matches the intensities of commodity use for the modeled production and consumption sectors for any regional aggregation of states. In addition, the SAM completes the circular flow with an account of factor incomes, household savings, trade, and institutional transfers.

Conceptually, the SAM represents a “snapshot” of the economy at the current point along a dynamic growth path. MRN simulates the dynamic growth path into the future in the absence of major changes to policies that are “on the books” today. This initial growth path is known as the “business-as-usual” case, or BAU. In other words, the initial snapshot is for a single year but the BAU case is a forecast over many years. Calibration of the BAU case from the initial snapshot provided by the SAM is completed by incorporating growth forecasts for industries, population, and carbon emissions.

The regional detail of MRN can be specified at any level of disaggregation down to the state level, depending on the needs of the analysis. Since carbon emissions are highly correlated with energy use, all the important energy sectors contained in the detailed

SAM are represented as individual sectors in MRN. CRA aggregates all of the remaining (non-energy) sectors in the SAM into five groups that capture the diversity in energy-intensity across all economic activities. MRN typically uses the ten production sectors in Table 2.3.

MRN also accounts for household energy uses, as well as all the productive sectors of the economy, so that MRN can correctly account for individuals' responses to higher fuel costs caused by carbon abatement policies. Importantly, personal transportation (i.e., automobile use) is included in the household energy uses, not in the transportation sector listed in Table 2.3.

**Table 2.5 MRN's 10 Energy Use Sectors**

| Energy Sectors            | Non-Energy Sectors       |
|---------------------------|--------------------------|
| Coal extraction           | Agriculture              |
| Oil and gas extraction    | Energy-intensive sectors |
| Oil refining/distribution | Manufacturing            |
| Gas distribution          | Transportation services  |
| Electricity generation    | Services                 |

MRN tracks CO<sub>2</sub> emissions from fossil fuel combustion and assumes that the costs of reducing other greenhouse gases are comparable to the cost of reducing carbon dioxide emissions. To incorporate carbon emissions in the model, an emissions permit is tracked for each of the three fossil fuel inputs (refined oil, natural gas, and coal). When there is a carbon cap, a fixed number of emissions allowances is assumed to be available in each modeled year.

If that limit is less than the BAU emissions level, a scarcity of allowances (i.e., when demand for allowances exceeds their supply) will exist. This scarcity increases the price on carbon (starting from zero) up to the point where demand for the allowances is reduced to the limit of their supply. Limiting the number of allowances available imposes an emissions constraint, and the permit price reflects the marginal cost of abatement.

### 2.5.3 Bottom-Up Modeling: NEEM Model

CRA's stand-alone North American Electricity & Environment Model (NEEM) is a linear programming model that simulates a competitive electricity market for the continental U.S. NEEM minimizes the present value of incremental costs to the electric sector while meeting electricity demand and complying with relevant environmental limits. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all state, regional and national, and seasonal and annual emissions caps for SO<sub>2</sub>, NO<sub>x</sub>, Hg, and CO<sub>2</sub>.

The least-cost outcome is the expected result in a competitive wholesale electricity market. As part of the cost minimization solution, NEEM produces forecasts of short-term and long-term decisions such as coal choices, investments in pollution control equipment, and new capacity additions in a manner that minimizes the total costs to the electric sector.

The model employs detailed unit-level information on all of the generating units in the U.S. and portions of Canada. All coal units larger than 200 MW in summer capacity are represented individually in the model, and other units are aggregated. NEEM models the evolution of the North American power system, taking into account demand growth, available generation, environmental technologies, and both present and future environmental regulations. The North American interconnected power system is modeled as a set of regions (generally NERC regions and NERC sub-regions) that are connected by a network of transmission paths.

Environmental regulations affect decisions about: (1) the mix and timing of new capacity, (2) retirement of existing units, (3) the mix and timing of environmental retrofits at existing facilities, (4) fuel choice, primarily by coal units, (5) dispatch of all units, (6) maintenance scheduling for all units, and (7) the flow of power among regions. NEEM captures all of these impacts in the process of optimizing unit responses to environmental policies. For cap-and-trade policies, NEEM also determines permit banking decisions.

In order to be integrated with MRN, NEEM has been formulated as a quadratic program instead of the linear program structure used in the stand-alone model. It solves for the optimal decisions by maximizing the present value of consumer and producer surplus subject to economic, technical, and policy constraints. The economic constraint is that the supply and demand for electricity be balanced in each region. Technical constraints include operational limits, maintenance requirements, and maximum output. Policy constraints include the required reserve margin and also state and Federal environmental constraints (i.e., emission caps, efficiency standards, and renewable portfolio standards).

The total surplus is equal to the area between the demand and supply curves for electricity. NEEM employs a linear demand curve that is benchmarked to the exogenous forecast of demand and the resulting marginal cost of providing electricity to meet this demand. The electricity supply curve represents the cost of supplying electricity, which includes (1) fixed and variable operating costs for all units, (2) fuel costs, (3) capital investments in new plants and retrofits at new and existing facilities, and (4) the cost of moving power between regions (wheeling charges). To (3) above, because of the long life-span of generating units, capital decisions affect decisions for several years. Therefore, NEEM's model horizon extends past the IRP planning horizon and out to 2050.

On the demand side of the economic constraint, NEEM dispatches to a load duration curve. The load shapes used in NEEM are based upon 2002 actual load profiles from EIA Form 411, and three separate load shapes corresponding to each regional interconnect (Eastern Interconnect, ERCOT, and Western Interconnect) are used. For

the eastern interconnect particularly, in which Ameren Missouri falls, the load shape is based upon the load profile for the ECAR region. Comparison of power prices in ECAR and Eastern Missouri, or EMO, (the NEEM region where Ameren Missouri is located) confirms a high correlation between the load profile for the ECAR region and that for the EMO region.

From this point, a load duration curve is created and ultimately inputted into the NEEM data file. The load duration curve first breaks up hourly demand into three seasons: summer, winter, and shoulder. The summer is defined as May through September; the winter as January, February, and December; and the shoulder period as March, April, October and November. Hourly demand in ECAR within each season is then sorted from highest to lowest and placed into load blocks.

For example, as shown in Table 2.4, the 25 hours in load block B11 represent the 25 hours with the highest load in ECAR within the shoulder months. It should be noted that the load blocks have been created to best represent the relative peakiness of energy demand, and, as such, there are fewer hours included in peak demand load blocks and more hours in off-peak demand load blocks. Given this demand structure, NEEM estimates annual regional power prices by load block.

Coal units (and other units of interest) are represented in detail as these are most affected by environmental regulation. All but small coal units are modeled at a unit level. All non-coal generating units in the U.S. are also represented in the model, with some level of unit aggregation.

In addition to coal units, NEEM represents the following generation technologies - natural gas combined cycle, natural gas combustion turbine, nuclear, integrated gasification combined cycle (also available with carbon capture and sequestration), hydroelectric, pumped storage hydro, and a range of renewable technologies. Renewable technologies include: wind, solar photovoltaic, solar thermal, landfill gas, biomass, and geothermal.

To analyze an environmental policy, NEEM must first be solved for a BAU case in which the policy is not in force. In addition, the BAU case must be consistent in that the exogenously specified demand (i.e., the demand input by the user) matches the demand expected under the set of policies and market conditions assumed in BAU.

**Table 2.5 Load Blocks, Seasons, and Count of Hours**

| Load Block | Season   | Number of Hours |
|------------|----------|-----------------|
| B1         | Summer   | 10              |
| B2         | Summer   | 25              |
| B3         | Summer   | 75              |
| B4         | Summer   | 100             |
| B5         | Summer   | 200             |
| B6         | Summer   | 300             |
| B7         | Summer   | 400             |
| B8         | Summer   | 500             |
| B9         | Summer   | 800             |
| B10        | Summer   | 1,262           |
| B11        | Shoulder | 25              |
| B12        | Shoulder | 200             |
| B13        | Shoulder | 600             |
| B14        | Shoulder | 900             |
| B15        | Shoulder | 1,203           |
| B16        | Winter   | 25              |
| B17        | Winter   | 100             |
| B18        | Winter   | 400             |
| B19        | Winter   | 700             |
| B20        | Winter   | 935             |

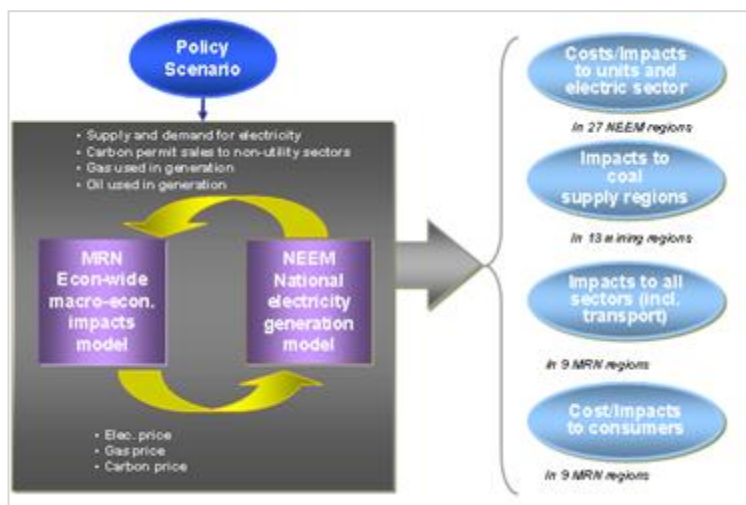
From the BAU-case solution, the equilibrium prices that are associated with exogenously specified demands are extracted. These prices along with the exogenously specified demand comprise the benchmark price and quantity points for the electricity demand curve. These electricity demand curves are defined for each region modeled. To solve for the carbon policy, or scenario case, the environmental policy of interest is applied, and the NEEM model is resolved. In the scenario case, electricity demand is no longer fixed and therefore demand is responsive to the environmental policy of interest. The model solves for the optimal set of decisions under the policy.

### 2.5.4 Integrating MRN with NEEM

As discussed previously, MRN accounts for all sectors except for the electric utility and coal supply sectors. The level of electric sector demand for natural gas, the supply of electricity, and the demand for electricity (all exogenous to MRN) are provided by the NEEM model.

The MRN model is then solved for a new equilibrium and provides NEEM with the supply and price of natural gas, a new electricity demand level and price of electricity, and the non-utility demand and price for coal. If allowing for emissions trading between utility and non-utility sectors, then the MRN model further provides the non-utility carbon allowance demand and price. In short, MRN supplies functions for electricity demand, non-utility coal demand, non-utility carbon allowance demand, and the supply of natural gas. NEEM accepts MRN's outputs as inputs and vice versa, as shown in Figure 2.4. This iterative process continues until convergence in the NEEM and MRN equilibrium price of electricity is achieved.

**Figure 2.5 Integration of MRN and NEEM**



### 2.5.5 Natural Gas Price Forecasts<sup>6</sup>

Natural gas prices represent one of the critical, nationally-defined uncertainties encompassed in the probability tree of MRN-NEEM scenarios. During probability encoding sessions conducted by CRA, Ameren Missouri subject matter experts

<sup>6</sup> 4 CSR 240-22.040(8)(A)1-3; 4 CSR 240-22.040(9)(C)

developed two discrete pathways for Henry Hub natural gas prices, allocating 50% probability to each pathway.

Figure 2.5 charts the high and low Henry Hub natural gas price trajectories, along with the average trajectory that arose during the tree trimming process for use with the Moderate EPA Regulation and BAU carbon policy cases.

There are two key observations to keep in mind. First, these elicited natural gas prices are baseline projections that, per the Ameren Missouri subject matter experts, do not reflect considerations of non-baseline load growth or of carbon policy.

When bundled with particular load growth and carbon policy settings in an MRN-NEEM scenario, these natural gas prices will change. Second, both experts expressed that they would prefer to use NYMEX futures of Henry Hub natural gas prices through 2014, the last year in which this futures market is liquid. It is not until 2015 that the high and low natural gas price trajectories start to diverge. After 2025, the expected value of baseline natural gas prices is the same in each future time period.

These baseline prices are (1) seasonally adjusted based upon historical monthly prices, governed by the month-to-season mapping in Table 2.5, and (2) regionally adjusted based upon June 2009 NYMEX futures of basis differentials from Henry Hub to 25 different U.S. plant gates.

**Table 2.5 MRN-NEEM  
Months to Seasons**

| Season   | Months                             |
|----------|------------------------------------|
| Summer   | May, June, July, August, September |
| Winter   | January, February, December        |
| Shoulder | March, April, October, November    |

Each of these regional plant gates are mapped to a contiguous NEEM region, resulting in delivered seasonal natural gas prices in each year for each natural gas-fired unit in the model. Due to higher natural gas demand in residential and commercial heating, the winter months feature higher natural gas prices.

**Figure 2.5 Elicited Henry Hub Natural Gas Prices**

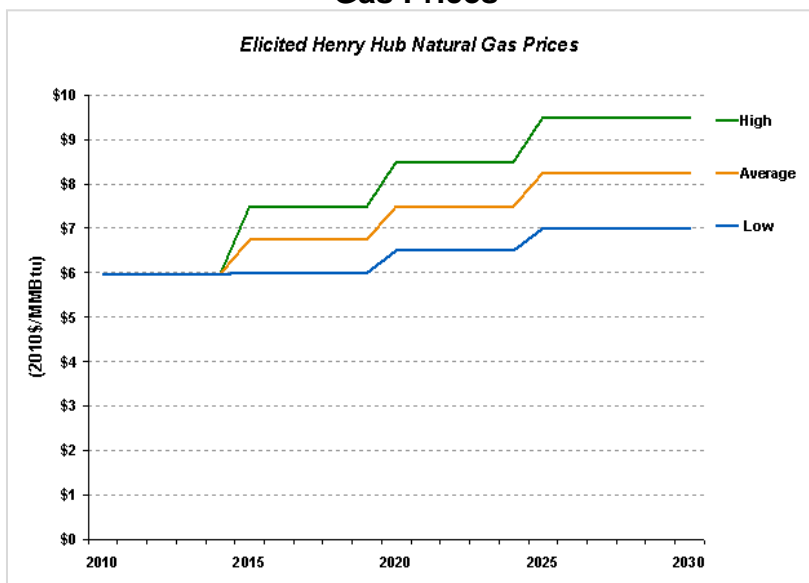
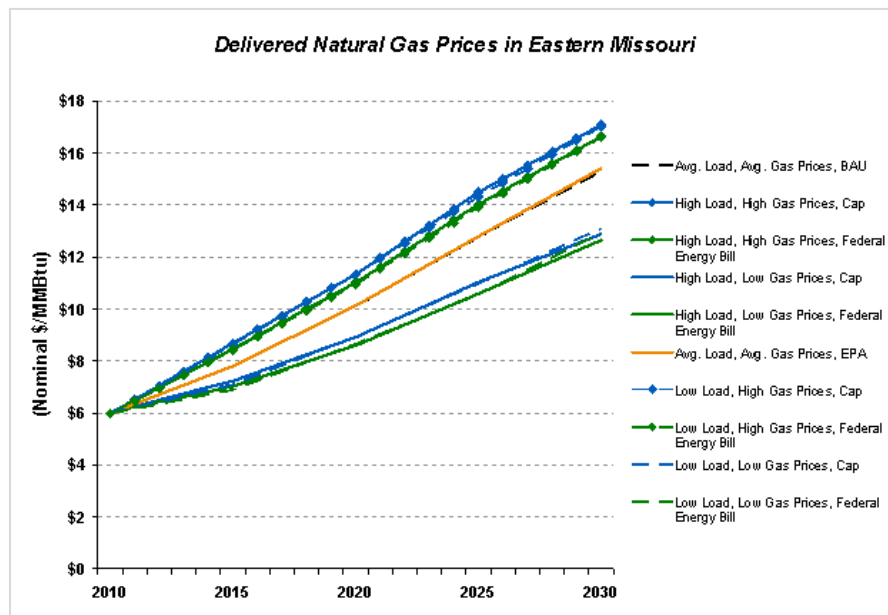


Figure 2.6 presents delivered natural gas prices in Eastern Missouri from each of the 10 modeled MRN-NEEM scenarios. Taking the baseline natural gas prices in Figure 2.5 and the particular load growth and carbon policy parameters as inputs, each MRN-NEEM scenario encompasses the feedback effects throughout the U.S. economy in generating equilibrium natural gas price levels. This is particularly important for a commodity like natural gas, whose consumption profile includes sectors outside of electricity generation.

**Figure 2.5 Natural Gas Prices in Eastern Missouri by MRN-NEEM Scenario**



In MRN-NEEM, elasticities of production determine supply responses to changes in fuel prices, and higher or lower prices incentivize or discourage exploration and production activities according to these elasticity parameters.

Natural gas price movements most formatively affect levels of natural gas usage because they provide a direct incentive to either ramp down or ramp up consumption. In the electric sector particularly, upswings in delivered natural gas prices can precipitate the switch to other cost-effective generating technologies and away from natural gas, leading to a decline in natural gas consumption.

The profitability and financial condition of producers is a function of the costs of extraction and the prevailing market price for natural gas.<sup>7</sup> Given a baseline natural gas price forecast and any policy prescriptions for CO<sub>2</sub> abatement or otherwise, the MRN NEEM model dynamically models net gains or losses to various production sectors, including oil and natural gas extraction and natural gas distribution. For trade-exposed

<sup>7</sup> 4 CSR 240-22.040(8)(A)1.B.

sectors facing international competitors, MRN-NEEM also simulates the leakage of economic activities outside of the U.S.

It should be noted that the model assumes perfectly functional and competitive commodities markets, and that it plots a least-cost path with perfect foresight of future prices and policy requirements. In only capturing this long term equilibrium, it does not acknowledge the likely costs resulting from abrupt market shifts, such as when electricity generators decisively shift from coal to natural gas or vice versa, that could impact natural gas producers' bottom line.

The MRN-NEEM model accounts for all environmental regulations currently projected through the planning horizon.<sup>8</sup> This includes any restrictions on SO<sub>2</sub>, NO<sub>x</sub>, and Hg emissions, and any binding RPS requirements throughout the country. Since combustion of natural gas produces significant amounts of CO<sub>2</sub> emissions, Ameren Missouri duly considered the potential for mandatory abatement. The CO<sub>2</sub> policy branches in the probability tree encapsulate what Ameren Missouri deems to be the full range of uncertainty for this variable. Each MRN-NEEM modeling scenario represented in that tree consequently addresses how various CO<sub>2</sub> policies concern natural gas production sectors.

The consumption of natural gas in the U.S. spans sectors characterized by varying degrees of competition, particularly in terms of fuel choice. The electricity generation sector is arguably the most price-elastic, largely due to oil, gas, and coal being relatively substitutable inputs. For instance, persistently high world oil prices, in combination with a smaller world natural gas resource base, leads to higher costs in developing domestic natural gas resources, higher wellhead natural gas prices, and in turn lower natural gas production.

Moreover, higher oil prices could spur greater gas-to-liquids (GTL) production globally, exerting further upward pressure on natural gas prices. In the case of LNG imports, contract prices are often tied directly to crude oil prices. The manifold ripple effects in these illustrative examples demonstrate how interrelated natural gas, coal, and fuel oil prices are. MRN-NEEM is capable of properly accounting for macroeconomic feedback effects between electricity demand, electricity prices, and natural gas, coal, and fuel oil prices and consumption levels.

Sustained high natural gas prices will incite expanded investment in transportation infrastructure.<sup>9</sup> The MRN-NEEM model assumes that enough transmission and distribution (T&D) capacity will be built to accommodate projected growth in natural gas consumption. In turn, MRN-NEEM fixes the regional basis differentials that represent

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<sup>8</sup> 4 CSR 240-22.040(8)(A)1.C.

<sup>9</sup> 4 CSR 240-22.040(8)(A)1.D.

the transportation costs from wellhead to end-use location. These regional basis differentials are drawn from June 2009 NYMEX futures at 25 plant gates across the U.S.

Ameren Missouri expects no restrictions on the use of natural gas in electricity generation within the IRP time period.<sup>10</sup> More probable restrictions on electricity generation from other fuel types could influence the pattern of natural gas consumption though. For instance, all of the non-BAU CO<sub>2</sub> policy cases envision a prohibition on new coal-fired plants without CCS. When the existing coal fleet retires, natural gas will move up in the merit order and increasingly serve base load demand.

CRA's MRN-NEEM model has been extensively peer-reviewed by such reputable organizations as the Stanford Energy Modeling Forum, the California Air Resources Board's peer review panel of economists for its analyses of AB32 costs, and (for an earlier version of the model) the International Panel on Climate Change (IPCC).<sup>11</sup> It has been found to represent a best-in-class energy and environmental model capable of producing the integrated projections of key IRP variables, including natural gas prices, essential to sound resource plan selection.

For modeling of resource plans Ameren Missouri used Henry Hub prices from CRA then Ameren Fuels and Services provided appropriate delivery costs for the various pipelines that supply Ameren Missouri natural gas units.

### 2.5.6 Coal Price Forecasts<sup>12</sup>

Unlike natural gas prices, NEEM actively models the dynamics of coal supply and transportation. As opposed to being an input, prices for each coal type are endogenously calculated within the model based upon the interaction of electric sector demand and annual coal supply curves. This implies that different levels of coal use in different periods lead to different average coal prices. Such an approach ensures internal consistency between allowance prices and coal prices, unlike other models in which coal prices are effectively fixed regardless of the rate of consumption.

Table 2.6 details the 22 different coal types in the NEEM model. These 22 coals were selected to best represent the major coal sub-markets and production regions in the U.S., as presented in Figure 2.7.

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<sup>10</sup> 4 CSR 240-22.040(8)(A)1.G.

<sup>11</sup> 4 CSR 240-22.040(8)(A)2.

<sup>12</sup> 4 CSR 240-22.040(9)(C)

Table 2.5 22 Different Coal Types

| Coal Type   | Rank                  | SO <sub>2</sub><br>(lbs/MMBtu) | Hg<br>(lbs/TBtu) | CO <sub>2</sub><br>(lbs/MMBtu) | Heat<br>Content<br>(Btu/lb) |
|---|-----------------------|--------------------------------|------------------|--------------------------------|-----------------------------|
| Northern Appalachia - High Btu,<br>Low Sulfur     | Bituminous            | 2.47                           | 12.31            | 205.3                          | 12,862                      |
| Northern Appalachia - High Btu,<br>High Sulfur    | Bituminous            | 3.95                           | 12.54            | 205.3                          | 12,900                      |
| Northern Appalachia - Low Btu,<br>Low Sulfur      | Bituminous            | 1.72                           | 15.98            | 205.3                          | 12,097                      |
| Northern Appalachia - Low Btu,<br>High Sulfur     | Bituminous            | 3.42                           | 20.87            | 205.3                          | 11,782                      |
| Central Appalachia, Compliance                    | Bituminous            | 1.12                           | 5.87             | 205.3                          | 12,731                      |
| Central Appalachia, Non-<br>Compliance - High Btu | Bituminous            | 1.50                           | 8.24             | 205.3                          | 12,637                      |
| Central Appalachia, Non-<br>Compliance - Low Btu  | Bituminous            | 1.80                           | 9.20             | 205.3                          | 12,030                      |
| Southern Appalachia                               | Bituminous            | 1.97                           | 8.73             | 205.3                          | 12,185                      |
| Illinois Basin, High Sulfur                       | Bituminous            | 5.20                           | 6.44             | 205.3                          | 11,395                      |
| Illinois Basin, Medium Sulfur                     | Bituminous            | 2.80                           | 6.44             | 205.3                          | 11,395                      |
| Illinois Basin, Low Sulfur                        | Bituminous            | 1.70                           | 6.44             | 205.3                          | 11,395                      |
| Central Basin                                     | Bituminous            | 4.82                           | 12.72            | 205.3                          | 12,077                      |
| Lignite   | Lignite               | 2.62                           | 10.80            | 215.4                          | 6,743                       |
| Powder River Basin, Montana                       | Sub-bituminous        | 1.19                           | 5.17             | 212.7                          | 9,043                       |
| Powder River Basin, Northern<br>Wyoming           | Sub-bituminous        | 0.89                           | 7.08             | 212.7                          | 8,380                       |
| Powder River Basin, Central<br>Wyoming            | Sub-bituminous        | 0.75                           | 5.42             | 212.7                          | 8,562                       |
| Powder River Basin, Southern<br>Wyoming           | Sub-bituminous        | 0.65                           | 5.76             | 212.7                          | 8,854                       |
| Rocky Mountain, Colorado                          | Western<br>Bituminous | 0.93                           | 3.65             | 205.3                          | 11,466                      |
| Rocky Mountain, Utah                              | Western<br>Bituminous | 1.04                           | 4.14             | 205.3                          | 11,554                      |
| Four Corners                                      | Bituminous            | 1.44                           | 4.20             | 205.3                          | 9,666                       |
| Import (Columbia)                                 | Bituminous            | 0.98                           | 5.52             | 205.3                          | 11,300                      |
| Import (Venezuela)                                | Bituminous            | 0.98                           | 5.52             | 205.3                          | 12,750                      |

Characteristics of each coal used by the NEEM model include (1) the rank of coal, (2) SO<sub>2</sub> content (lb/MMBtu), (3) mercury content (lbs/TBtu), and (4) the energy content per pound of coal:

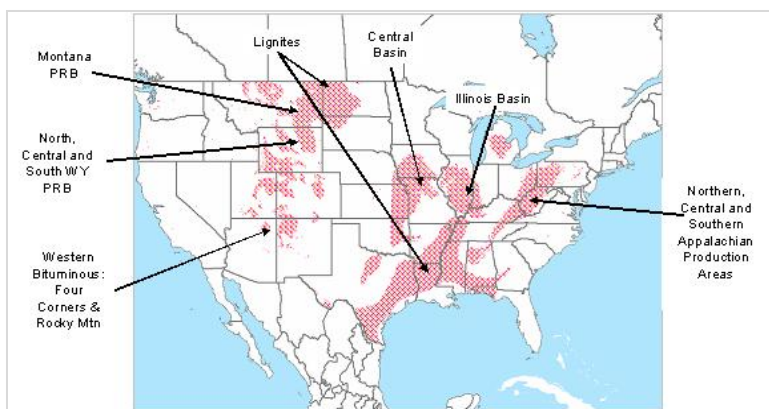
- (1) Rank: There are four different ranks of coal within the NEEM coal file. These are bituminous, western bituminous, sub-bituminous, and lignite. These classifications are required because of the specific boiler technology specifications required to burn specific ranks of coal. The model does not allow cost-free switching into sub-bituminous coals, for instance, unless a plant undertakes certain equipment upgrades.
- (2) SO<sub>2</sub> content: The SO<sub>2</sub> content is based on information from the Norwest model of the domestic coal supply market.
- (3) Mercury content: The source for information on the mercury content of coals is derived from the U.S. EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort," or ICR. As part of the ICR effort, coal generators greater than 25 MW were required to

sample the mercury content of their coal shipments in 1999 at least three times each month and submit the information to the U.S. EPA on a quarterly basis. U.S. EPA compiled this information and made it available through its website.

- (4) Energy content: The source of the Btu per pound for each coal type is also based on the Norwest model.

For every mine in the nation, Norwest developed models of both production capabilities and minemouth prices per ton of coal production. Using these data along with supplemental information from the EIA, CRA created step-wise supply curves based on tranches. The number of tranches and the quantity of tons within each tranche vary by coal type and are a function of mine capabilities. These annual supply curves indicate the marginal cost of mining an incremental ton of each coal type in each year of the IRP planning horizon.

**Figure 2.5 NEEM Coal Supply Representation**



Another distinguishing feature of the NEEM model is its exceptional detail of coal electricity generating units. Every existing coal unit with a summer capacity of 200 MW or greater is represented individually in the model, and units under 200 MW are grouped into aggregates of similar size and location. However, both Ameren Missouri coal units under 200 MW in summer capacity, Meramec 1 and Meramec 2, were modeled separately to provide more precise insights regarding the Ameren Missouri coal fleet.

Each coal that can be delivered to a unit has a transportation cost from the mine to the plant gate. CRA represents transportation costs with a set of transportation matrices structured upon four modes of coal transport: barge, truck, rail, and mixed mode (i.e., “trans-load” from rail to barge). The matrices are then populated based on information in the Platts CoalDat database.

Coal plants that do not have a viable delivery option via one of the modes of transportation have a blank entry in the matrix. If there is a delivery option, then the delivery cost is calculated based on one of the following: (1) the actual transport cost for the plant, (2) the weighted average transport cost for all plants in the region for the particular coal/mode of transportation combination, or (3) a CRA estimate of transport

cost based on the plant's distance from the production basin and the cost per ton-mile for that coal.

Starting in 2011, coal delivery costs in all regions except Missouri and Illinois escalate annually at 4% nominal growth rate in order to simulate the increased costs of new rail contracts as existing contracts expire. In Missouri and Illinois, Ameren Missouri projected that transport costs should increase at a much steeper rate, climaxing at 186% and 136% increases, respectively, in 2030.

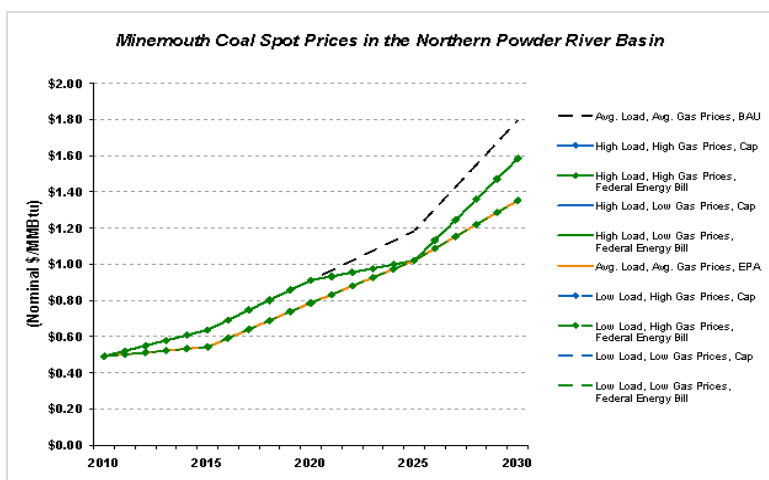
NEEM's partial equilibrium model provides a set of minemouth prices for each coal type and delivered prices for feasible coals to each plant. At a higher level, this equilibrium is dependent upon the demand for electricity and the demand for coal relative to other fuel types. All other things held constant, greater electricity demand will translate into greater coal consumption, while higher natural gas prices will stimulate demand for coal and thus translate into higher coal prices.

In the northern region of the PRB, the higher load scenarios (represented by the solid lines) induce higher coal consumption and, in turn, minemouth prices as shown in Figure 2.8. Natural gas prices, on the other hand, do not seem to have a significant effect on mine mouth coal prices from the northern PRB.<sup>13</sup>

Section 2.6 of this chapter contains tables by year by scenario of minemouth coal prices for coals typically burned by the Ameren Missouri fleet; that is, the two NEEM coal types from different regions of the Powder River Basin and one NEEM coal from the Illinois Basin.

Given supply curves that determine minemouth coal prices and transportation options that determine delivery prices from mine to plant gate, each NEEM coal unit selects the least-cost fuel from the broad array of options available. For one, NEEM weighs the sulfur and mercury content of each obtainable coal against (1) the environmental controls currently installed or those that could be installed in the future and (2) the prevailing environmental regulations in the region. Two, NEEM compares the energy content per pound across the various coal options.

**Figure 2.5 Minemouth Coal Prices  
Northern Powder River Basin**



<sup>13</sup> 4 CSR 240-22.040(8)(A)3.

As one example, the coals from the various regions in the Powder River Basin range from 8,380 Btu/lb to 9,043 Btu/lb, measured against an energy content of 11,395 Btu/lb for the Illinois Basin coals. Each coal unit with access to both of these supply regions will have to weigh PRB coals' disadvantage in terms of energy content against its significant advantage in terms of lesser SO<sub>2</sub> content.

Especially for units not currently equipped with FGD retrofit technology, switching to PRB coals to reduce SO<sub>2</sub> emissions might represent the most economic decision. This is contingent, however, on the unit's ability to burn sub-bituminous coals like those from the Powder River Basin. For those units without this ability, NEEM does allow for what is called a fuel switch retrofit. This retrofit covers the costs of boiler modifications and coal handling equipment that would likely result from the added capability of burning sub-bituminous fuels. Against this backdrop, and with perfect foresight through the planning horizon, NEEM chooses the fuel strategy that minimizes the net present value of costs to each coal unit in the U.S.

The NEEM model formulates annual supply curves for 22 distinct coal types that represent different regional sources, ranks, and sulfur and mercury contents. These supply curves are based upon detailed information of production capabilities and costs per ton removed at every mine in the U.S. for each year in the planning horizon. As such, they incorporate estimates of domestic recoverable coal resources and baseline trends in exploration and production (E&P) technological improvements. Coal price levels are endogenously calculated to be consistent with the coal consumption levels implied by the supply curves and with allowance prices.<sup>14</sup>

The profitability and financial condition of producers is a function of the costs of extraction and the prevailing minemouth prices for various coal types. The annual coal supply curves for each of the 22 coal types in the NEEM model reflect the extraction costs facing U.S. coal producers, and, in conjunction with the demand for electricity, also determine coal prices. Moreover, the MRN-NEEM modeling framework incorporates the macroeconomic effects stemming from fluctuations in electricity demand, CO<sub>2</sub> prices, and natural gas prices, all of which affect the demand for coal.<sup>15</sup>

Since coal prices are endogenously computed in each model year based upon flexible supply and demand functions that adjust optimally to market conditions, business-as-usual considerations of environmental factors, competition, and regulation on producers are all implicitly acknowledged by the model. Additional policy prescriptions that could

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<sup>14</sup> 4 CSR 240-22.040(8)(A)1.A.

<sup>15</sup> 4 CSR 240-22.040(8)(A)1.B.

materially affect coal producers are represented in the probability tree (e.g., the prohibition new coal builds in all non-BAU scenarios).<sup>16</sup>

The matrix of transportation costs described above tabulates the costs of the up to four delivery options (truck, rail, barge, and mixed mode) available to each NEEM coal unit. This matrix is based upon historical data from the Platts CoalDat database. Further, transportation costs increase as described above to replicate what Ameren Missouri judges to be a looming tight rail market as existing contracts expire. From a more general perspective, although the NEEM model does not simulate expansions to the coal transportation network, it assumes that ample infrastructure exists to support the full range of endogenously-determined demand levels.<sup>17</sup>

MRN-NEEM takes for granted any expansions in T&D infrastructure necessary to sustain equilibrium coal demand levels. Depending upon its coverage of the economy, federal CO<sub>2</sub> abatement policies could also penetrate directly into energy intensive coal transport industries, like railroads. MRN-NEEM simulates the increased sector-wide costs that coal rail transporters would incur under such a regime, although these costs are not presently translated into changes in relative costs of delivery for each type of coal considered in the electric sector dispatch decisions. Further, the set of MRN-NEEM modeling scenarios in the probability tree fully spans the range of CO<sub>2</sub> policy uncertainty surrounding the coal transportation and all other energy-intensive sectors.<sup>18</sup>

All of the non-BAU scenarios in the probability tree prohibit the construction of new coal-fired power plants without CCS capabilities. The other features of the carbon policy branches (e.g., the national RES in the Federal Energy Bill cases, CO<sub>2</sub> prices in the Cap-and-Trade cases) represent other government programs that will affect the demand for coal, particularly within the electricity generation sector.<sup>19</sup>

CRA's MRN-NEEM model has been extensively peer-reviewed by such reputable organizations as the Stanford Energy Modeling Forum, the California Air Resources Board's peer review panel of economists for its analyses of AB32 costs, and (for an earlier version of the model) the International Panel on Climate Change (IPCC). It has been found to represent a best-in-class energy and environmental model capable of producing the integrated projections of key IRP variables, including natural gas prices, essential to sound resource plan selection. In addition, Norwest represents one of the

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<sup>16</sup> 4 CSR 240-22.040(8)(A)1.C.

<sup>17</sup> 4 CSR 240-22.040(8)(A)1.D.

<sup>18</sup> 4 CSR 240-22.040(8)(A)1.E.

<sup>19</sup> 4 CSR 240-22.040(8)(A)1.G.

world's foremost and most fully-integrated energy and natural resource consultancies, with over thirty years of experience in the American coal industry.<sup>20</sup>

For modeling of resource plans Ameren Missouri used minemouth prices from CRA then Ameren Fuels and Services provided appropriate delivery costs as seen in table 2.20. Table 2.7 summarizes which coal type is delivered to Ameren Missouri coal plants and a new generic coal unit.

**Table 2.5 Coal Types by Plant**

|             | PRB South Wyoming | PRB North Wyoming | IL Basin High Sulfur |
|-------------|-------------------|-------------------|----------------------|
| Labadie     | 87%               | 13%               | --                   |
| Meramec     | 65%               | 35%               | --                   |
| Rush Island | --                | 100%              | --                   |
| Sioux       | 80%               | --                | 20%                  |
| New Unit    | 100%              | --                | --                   |

### 2.5.7 Emissions Price Forecasts<sup>21</sup>

The probable environmental costs related to SO<sub>2</sub>, NO<sub>x</sub>, Hg, and CO<sub>2</sub> emissions for generic new unit types in the MRN-NEEM model are summarized in Table 2.8.

**Table 2.58 Estimated Mitigation Costs for Generic New Capacity**

| New Unit Type | Emission Rate (lbs/MWh or TWh)* |                 |              |                 | Mitigation Costs (\$/MWh)   |                 |    |                 |
|---------------|---------------------------------|-----------------|--------------|-----------------|---|-----------------|----|-----------------|
|               | SO <sub>2</sub>                 | NO <sub>x</sub> | Hg           | CO <sub>2</sub> | SO <sub>2</sub>   | NO <sub>x</sub> | Hg | CO <sub>2</sub> |
| Coal          | 0.12 - 0.92                     | 0.53            | 1.61 - 9.23  | 1,881           | Mitigation Cost = C <sub>i</sub> * Emissions Rate,<br>where C <sub>i</sub> = Allowance Price per lb |                 |    |                 |
| IGCC          | 0.11 - 0.90                     | 0.61            | 1.58 - 9.04  | 1,842           |   |                 |    |                 |
| Coal with CCS | 0.13 - 1.01                     | 0.68            | 1.77 - 10.13 | 207             |   |                 |    |                 |
| CC            | -                               | 0.14            | -            | 817             |   |                 |    |                 |
| CT            | -                               | 0.87            | -            | 1,265           |   |                 |    |                 |
| Nuclear       | -                               | -               | -            | -               |   |                 |    |                 |
| Renewables    | -                               | -               | -            | -               |   |                 |    |                 |

For coal-based technologies, namely advanced coal, integrated gasification combined cycle (IGCC), and coal with carbon capture and sequestration (coal with CCS), SO<sub>2</sub> and Hg emissions are a function of both the generation/retrofit technology and the type of coal being burned.

CRA's North American Electricity & Environment Model, or NEEM, provides exceptional detail of the U.S. coal sector, with coal supply curves representing 22 distinct coal supply regions and coal types. These coal supply regions are linked to the generation units by a coal transportation matrix with unit-specific transportation costs.

Naturally, each variety of coal differs in the content of SO<sub>2</sub> and Hg per unit of heat input, and the lower and upper bounds for emission rates given in Table 2.5.5 reflects this range (note that the Hg emissions rate is given in lbs/TWh, whereas all other rates are

<sup>20</sup> 4 CSR 240-22.040(8)(A)2.

<sup>21</sup> 4 CSR 240-22.040(8)(D)1-2; 4 CSR 240-22.040(9)(C)

in lbs/MWh). NO<sub>x</sub> emission rates, on the other hand, are rather less dependent on the type of coal being used, and are assumed solely determined by generation technology.

NEEM assumes CO<sub>2</sub> emission rates of 205.3 to 215.4 lbs/MMBtu (depending on the type of coal) for coal-based capacity, with CCS technology achieving a 90% reduction in CO<sub>2</sub> emissions. The CO<sub>2</sub> emissions for natural gas-fired combined cycle (CC) and combustion turbine (CT) units are assumed to be 116.7 lbs/MMBtu. NO<sub>x</sub> emission rates range from 0.02 lbs/MMBtu (CC) to 0.08 lbs/MMBtu (CT) among emitting new unit types. These rates, in terms of energy input, are then multiplied by the fully loaded heat rate to produce the emission rates of Table 2.5.6, given in terms of the electricity produced.

To clarify, consider the CO<sub>2</sub> emission rate given below for IGCC with CCS capacity. NEEM assumes that this technology captures and sequesters 90% of the 212.7 pounds of CO<sub>2</sub> emitted per unit of energy input. Thus, the rate of CO<sub>2</sub> released into the atmosphere from a coal with CCS generator is 21.27 lbs/MMBtu. NEEM assumes a heat rate of 9.713 MMBtu/MWh for this capacity type. As a result, the emission rate for coal with CCS units is equal to the product of 21.27 lbs/MMBtu and 9.713 MMBtu/MWh, equal to 207 lbs/MWh.

The cost of mitigating the emissions of a particular pollutant is dependent upon the emissions rate and the market price of an emissions allowance, Ct. In the cap-and-trade scenarios, the market price of CO<sub>2</sub> is represented by a simple CO<sub>2</sub> price. Recall that there is no explicit price on CO<sub>2</sub> emissions in the Federal Energy Bill, Moderate EPA Regulation, and BAU branches of the probability tree.

Similarly, this analysis does not simulate the disbanded CAMR cap-and-trade scheme for mercury emissions, and, in turn, does not produce allowance prices for mercury. For SO<sub>2</sub> and NO<sub>x</sub> emissions, however, NEEM estimates allowance prices against all existing environmental regulations in fully-functioning allowance price markets. These are:

- Title IV/Clean Air Interstate Rule (CAIR) for SO<sub>2</sub> – Title IV melds into the CAIR SO<sub>2</sub> program beginning in 2010 when units in the CAIR region (including units in Missouri) are required to submit two allowances for every ton emitted. This increases to 2.86 allowances per ton emitted in 2015 and beyond;
- CAIR Ozone Season NO<sub>x</sub> – the CAIR Ozone Season NO<sub>x</sub> program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015 – this cap is applicable for the summer months of May through September;

- CAIR Annual NO<sub>x</sub> – the CAIR Annual NO<sub>x</sub> program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015.

NEEM dynamically calculates allowance prices for SO<sub>2</sub> and NO<sub>x</sub> emissions subject to each of the above constraints. In general, if an emissions cap is binding at any point during the model horizon, the allowance price is equal to the marginal cost of abating one more pound or ton of pollutant.

NEEM allows for banking, so emissions in a given year do not necessarily match the prescribed annual limits of the program, as given in Table 2.9.

The degree to which the prescribed caps are binding (i.e., the level of emissions), combined with optimal banking choices, sets the equilibrium allowance price. NEEM determines unit-level emissions for SO<sub>2</sub> and NO<sub>x</sub> based on unit-specific fuel choices, existing equipment, retrofit choices, and dispatch, the details of which are described below.

**Table 2.59 SO<sub>2</sub>, NO<sub>x</sub>, and Hg Emissions Limits**

|      | SO <sub>2</sub> | NO <sub>x</sub> |              |
|------|-----------------|-----------------|--------------|
|      | Title IV/CAIR   | CAIR Ozone      | CAIR Annual  |
| Year | Million Tons    | Thousand Tons   | Million Tons |
| 2010 | 8.95            | 568             | 1.722        |
| 2015 | 8.95            | 485             | 1.268        |
| 2018 | 8.95            | 485             | 1.268        |
| 2020 | 8.95            | 485             | 1.268        |
| 2030 | 8.95            | 485             | 1.268        |

SO<sub>2</sub> emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Initial data that is used to calculate SO<sub>2</sub> emissions include the quantity and characteristics of the existing coal fleet, particularly the capacity, existing retrofit equipment, and coal types that can be burned at each unit. NEEM models existing federal SO<sub>2</sub> legislation and rules including Title IV and CAIR. These provide a cap on the level of SO<sub>2</sub> emissions.

The model also includes an estimate of the existing bank of SO<sub>2</sub> allowances entering 2009 (approximately 8.8 million tons) and allows for additional banking or withdrawals from the bank in order to comply with the cap in the most cost-efficient manner possible. The emissions from existing coal units will change over time in response to the SO<sub>2</sub> allowance price projected by NEEM and the SO<sub>2</sub> reduction options available to each unit. Units can reduce their SO<sub>2</sub> emissions in a number of ways.

First, units that do not have a flue gas desulfurization (FGD) retrofit may add one. The cost of these retrofits is a function of the size of the unit and the cost parameters included in Table 2.10.

**Table 2.5 Retrofit Costs and Characteristics**

| <i>All costs are in 2010 dollars.</i> | Reference Size | Capital Cost (\$/kW) | Fixed O&M (\$/kW-yr) | Variable O&M (\$/MWh) | Removal Rate |
|---------------------------------------|----------------|----------------------|----------------------|-----------------------|--------------|
| FGD                                   | 500            | \$351                | \$11.53              | \$2.18                | 98%          |
| SCR                                   | 243            | \$234                | \$0.85               | \$0.77                | 90%          |
| SNCR                                  | 150            | \$23.44              | \$0.35               | \$1.13                | 35%          |
| ACI90                                 | 250            | \$2.24               | \$0.90               | \$0.61                | 90%          |
| RPI90                                 | 250            | \$61.55              | \$1.12               | \$0.61                | 90%          |
| CCS (For Coal)                        | N/A            | \$1,706              | \$1.56               | \$2.76                | 90%          |

A unit will add an FGD if the cost of installing the FGD, as measured in dollars per ton of SO<sub>2</sub> removed, is less than the cost of purchasing allowances for that unit over the useful life of the retrofit.

A second option to reduce SO<sub>2</sub> emissions is to change coal types. As shown in Table 2.6, each coal has different SO<sub>2</sub> contents. If a coal can be delivered to the unit then it can switch to burning that coal.

For units that do not currently burn Powder River Basin (PRB) coal, a capital cost would have to be incurred to account for the boiler modifications necessary to burn PRB coals.

Lastly, a unit can reduce its SO<sub>2</sub> emissions by generating less, particularly if SO<sub>2</sub> emissions costs push it higher up the dispatch curve. All new coal units are assumed to include an FGD and therefore have an SO<sub>2</sub> emission rate that reflects 98% removal of inlet SO<sub>2</sub>.

NO<sub>x</sub> emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Unlike SO<sub>2</sub>, NEEM includes initial NO<sub>x</sub> emission rates for coal, natural gas, and oil-fired plants. This information is based on NO<sub>x</sub> rates reported as part of the EPA's Continuous Emissions Monitoring System (CEMS). As previously described, all emitting units are subject to the caps prescribed by the CAIR NO<sub>x</sub> Ozone Season and CAIR NO<sub>x</sub> Annual programs.

As with SO<sub>2</sub>, there are multiple options for reducing NO<sub>x</sub> emissions on existing units. Two retrofits are available to coal units: Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR). Units will install these retrofits if the cost per ton of NO<sub>x</sub> removed is less than the prevailing NO<sub>x</sub> allowance price. The costs and characteristics of SCR and SNCR are included in Table 2.10. The other means through which existing unit can reduce NO<sub>x</sub> emissions is by simply generating less. New units, in contrast, are assumed to have controls in place necessary to meet New Source Performance Standards (NSPS). As such, new coal units have a NO<sub>x</sub> emission rate of 0.06 lbs/MMBtu, new combined cycle units have a NO<sub>x</sub> emission rate of 0.02 lbs/MMBtu, and new combustion turbines have a NO<sub>x</sub> emission rate of 0.08 lbs/MMBtu.

Similar to SO<sub>2</sub> emissions, Hg emissions are only from coal-fired units. Hg emissions for any coal unit are a function of the coal burned and the pollution control equipment in place. While there are Hg-specific retrofits, Hg can also be removed as a co-benefit from some non-Hg controls such as FGDs and SCRs.

The Hg co-benefits given in Table 2.11 were provided to CRA by the Electric Power Research Institute (EPRI), and were used as part of comments filed in response to the then-proposed Clear Air Mercury Rule (CAMR).

An earlier table, Table 2.10, lists the two mercury control options available to coal-fired units in NEEM in order to comply with the 60% and 90% mercury reduction requirements in 2015 and 2020.

The Activated Carbon Injection (ACI90) technology can only be operated in conjunction with bituminous coal use, and represents a less capital-intensive option for larger units that can rely on existing particulate matter (PM) controls for mercury co-benefits. This ACI90 is only available to units that have already installed a fabric filter. For units without fabric filters, the RPJ90 option is naturally more expensive because it includes the costs of a fabric filter.

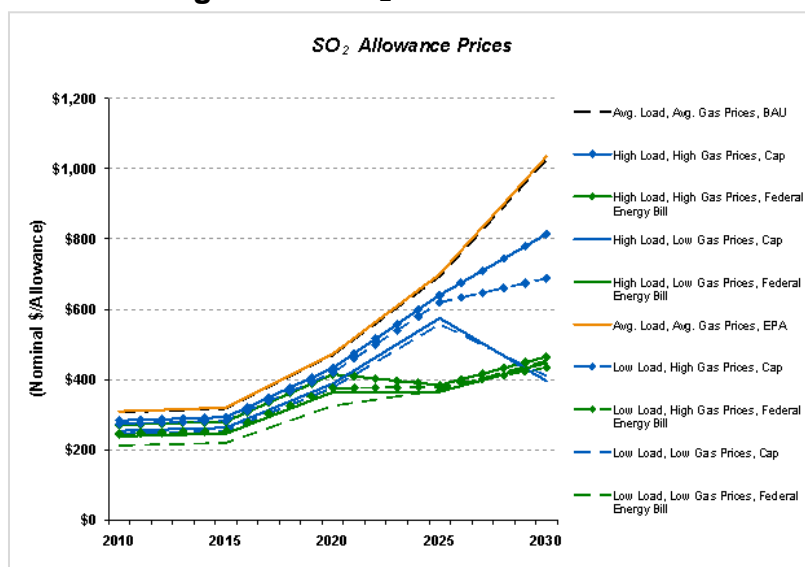
With perfect foresight through the end of the modeling horizon, NEEM then optimizes generation patterns, fuel choices and consumption levels, and potential retrofit installations in a manner that minimizes the net present value of total system costs while meeting all reserve margin requirements and complying with all environmental regulations. Allowing for the banking (and subsequent withdrawal) of allowances that could result if permit prices rise faster than the 5% discount rate, NEEM charts an optimal allowance price path through the model horizon.

Again, the resulting allowance price represents the marginal cost of abating one more pound or ton of the pollutant; that is, “Ct,” in the equation shown in the column titled “Mitigation Costs” in an earlier table, Table 2.8.

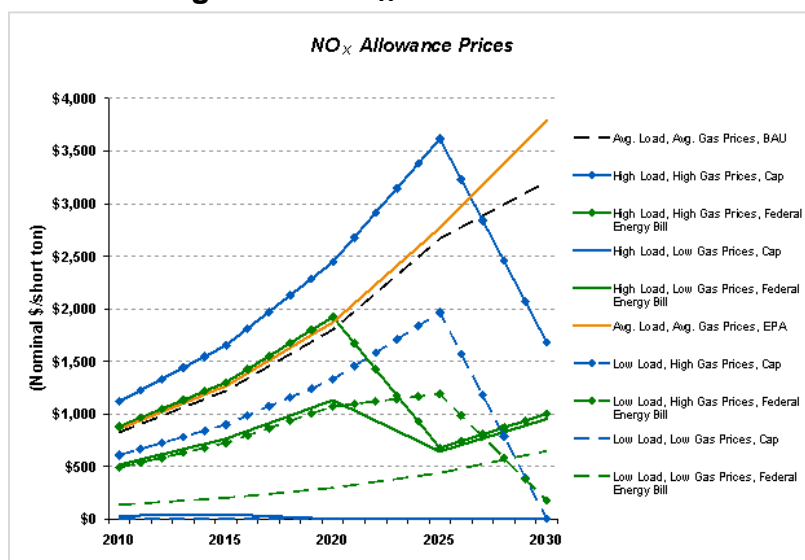
The SO<sub>2</sub> prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.9.

**Table 2.5 Mercury (Hg) Co-Benefits**

| Equipment in Place |                         |                         | % Removal of Inlet Hg |     |         |
|--------------------|-------------------------|-------------------------|-----------------------|-----|---------|
| PM Control         | SO <sub>2</sub> Control | NO <sub>x</sub> Control | Bituminous            | PRB | Lignite |
| Fabric Filter      | Dry FGD                 | No SCR                  | 85                    | 25  | 10      |
|                    |                         | SCR                     | 90                    | 25  | 10      |
|                    | Wet FGD                 | No SCR                  | 85                    | 75  | 40      |
|                    |                         | SCR                     | 90                    | 75  | 40      |
|                    | No FGD                  | No SCR                  | 75                    | 65  | 10      |
|                    |                         | SCR                     | 75                    | 65  | 10      |
| Cold-Side ESP      | Dry FGD                 | No SCR                  | 50                    | 15  | 10      |
|                    |                         | SCR                     | 85                    | 15  | 10      |
|                    | Wet FGD                 | No SCR                  | 60                    | 35  | 35      |
|                    |                         | SCR                     | 85                    | 35  | 35      |
|                    | No FGD                  | No SCR                  | 35                    | 20  | 10      |
|                    |                         | SCR                     | 35                    | 20  | 10      |
| Hot-Side ESP       | Dry FGD                 | No SCR                  | 0                     | 0   | 0       |
|                    |                         | SCR                     | 0                     | 0   | 0       |
|                    | Wet FGD                 | No SCR                  | 55                    | 30  | 30      |
|                    |                         | SCR                     | 85                    | 30  | 30      |
|                    | No FGD                  | No SCR                  | 20                    | 0   | 0       |
|                    |                         | SCR                     | 20                    | 0   | 0       |
| Venturi Scrubber   | Dry FGD                 | No SCR                  | 25                    | 15  | 15      |
|                    |                         | SCR                     | 60                    | 15  | 15      |
|                    | Wet FGD                 | No SCR                  | 25                    | 15  | 15      |
|                    |                         | SCR                     | 60                    | 15  | 15      |
|                    | No FGD                  | No SCR                  | 20                    | 5   | 5       |
|                    |                         | SCR                     | 20                    | 5   | 5       |

Figure 2.5 SO<sub>2</sub> Allowance Prices

NO<sub>x</sub> prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.10. For NO<sub>x</sub> allowance prices, Figure 2.10 presents prices under the CAIR NO<sub>x</sub> Annual cap.

Figure 2.5 NO<sub>x</sub> Allowance Prices

CO<sub>2</sub> permit prices in the cap-and-trade scenarios are shown in Table 2.12.

**Table 2.5 CO<sub>2</sub> permit prices**

| Year | CO <sub>2</sub> Price<br>(2010\$/metric ton) |
|------|--|
| 2015 | \$7.50                                       |
| 2020 | \$17.50                                      |
| 2025 | \$21.50                                      |
| 2030 | \$29.25                                      |
| 2035 | \$37.00                                      |
| 2040 | \$47.22                                      |

Finally, Table 2.13 shows when the SO<sub>2</sub>, NO<sub>x</sub>, and Hg retrofits are installed on Ameren Missouri coal plants. The year given represents the year when NEEM installs a retrofit on at least half of the unit's capacity.

**Table 2.5 SO<sub>2</sub>, NO<sub>x</sub>, and Mercury Retrofits**

| Unit          | FGD  | SCR | ACI90 | RPJ90 | CCS |
|---------------|------|-----|-------|-------|-----|
| Sioux 1       | 2010 |     |       | 2015  |     |
| Sioux 2       | 2010 |     |       | 2015  |     |
| Meramec 1     |      |     |       | 2015  |     |
| Meramec 2     |      |     |       | 2015  |     |
| Meramec 3     |      |     |       | 2015  |     |
| Meramec 4     |      |     |       | 2015  |     |
| Rush Island 1 | 2020 |     |       | 2015  |     |
| Rush Island 2 | 2020 |     |       | 2015  |     |
| Labadie 1     | 2020 |     |       | 2015  |     |
| Labadie 2     | 2020 |     |       | 2015  |     |
| Labadie 3     | 2020 |     |       | 2015  |     |
| Labadie 4     | 2020 |     |       | 2015  |     |

### 2.5.8 Electricity Price Forecasts<sup>22</sup>

Forecasts of the market cost of power were derived from MRN-NEEM projections of wholesale electricity prices. The integrated MRN-NEEM modeling framework described in subsections 2.5.1 through 2.5.4 furnishes electricity prices by load block and year for the Eastern Missouri (EMO) region encompassing Ameren Missouri's service territory. This equilibrium electricity price represents the marginal cost of supplying an incremental MWh of electricity in a particular region.

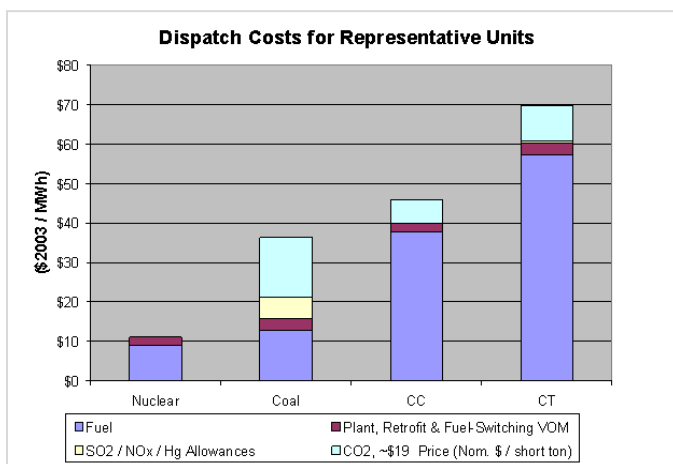
It accounts for (1) the dispatch costs of existing resources and potential new additions, (2) planned maintenance and forced outages at generating units in the region, (3) compliance with all environmental regulations, and (4) a dynamic transmission system that allows for imports and exports between regions. Having sorted all available capacity in a NEEM region by dispatch costs, the model then assesses where the so-constructed supply curve intersects with the demand in a given load block. This determines the wholesale electricity price.

<sup>22</sup> 4 CSR 240-22.050(2)

The composition of dispatch, or variable, costs for four representative unit types in the NEEM model are shown in Figure 2.11. The relative variable costs of different capacity types determine the merit order of dispatch and, in turn, the shape of the electricity supply curve.

They include fuel costs; plant, retrofit, and fuel-switching variable O&M (VOM) costs; SO<sub>2</sub> and NO<sub>x</sub> allowance costs; and any prevailing CO<sub>2</sub> abatement costs (CO<sub>2</sub> prices and/or CCS transportation and storage costs). The unit types with the lowest variable costs will constitute the bottom of the supply curve and serve base load demand. As given below, nuclear capacity often sits at this point on the curve.

**Figure 2.5 Dispatch Costs**



As one moves up the supply curve, the variable costs of dispatch options get progressively higher. Figure 2.11 shows that coal generators generally have lower variable costs than natural gas-fired CC and CT capacity in that order, largely due to differences in fuel costs. However, an aggressive CO<sub>2</sub> policy can transform the merit order of dispatch options, particularly between those fired by coal and natural gas.

Electricity demand is a function of the time of the day and of the season of the year, and these diurnal variations are captured across the model's 20 load blocks. For example, load block B1, which contains the highest demand hours in the summer season, features higher electricity demand than load block B10, which contains the lowest demand hours in the summer. In turn, electricity prices are higher in B1 than in B10.

Demand in typical peak and off-peak load blocks is represented respectively in Figure 2.12 and Figure 2.13 by vertical lines. The intersection of this perfectly inelastic demand curve and the upwards sloping supply curve sets the equilibrium wholesale electricity price, "P\*peak" and "P\*off peak."

Figure 2.5 Determination of Electricity Prices in a Peak Load Block

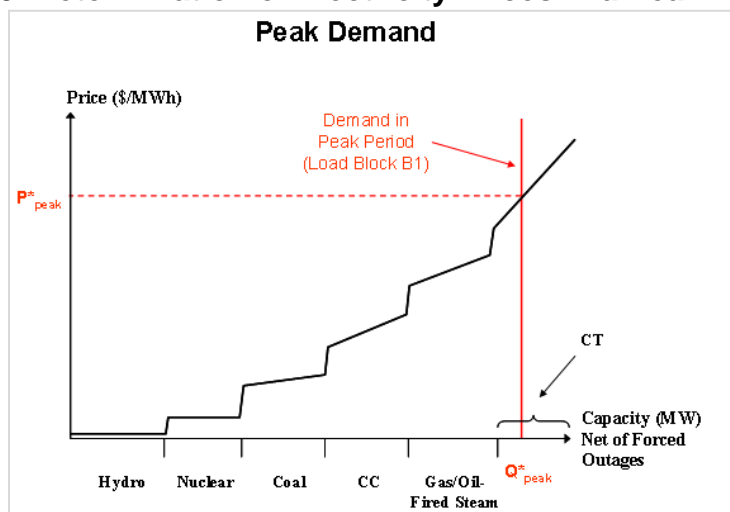
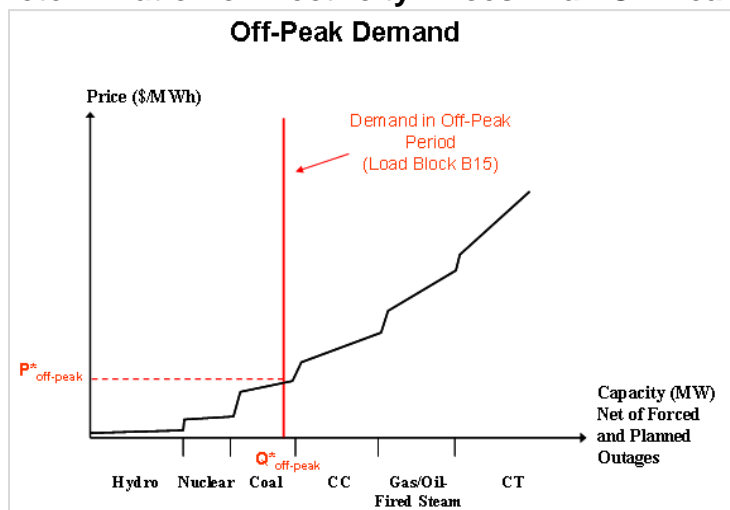


Figure 2.5 Determination of Electricity Prices in an Off-Peak Load Block



These two graphical depictions delineate the dynamics of electricity pricing in the NEEM model.

- First, demand in an off-peak period is predictably less than demand in an on-peak period, which shifts the inelastic demand curve to the left towards capacity with less expensive dispatch. As such,  $P^*_{\text{peak}}$  is greater than  $P^*_{\text{off-peak}}$ .
- Second, NEEM optimally chooses the shoulder, off-peak load blocks for nuclear and coal capacity to undergo planned maintenance. With less inexpensively dispatched capacity available, the steps in the supply curve corresponding to those unit types shrink. This shortening of the supply curve partially mitigates the difference in off-peak and on-peak prices.

- Third, the supply curve is not a continuous function, and instead is stratified by the unique variable costs of each generation technology. In turn, incremental changes in demand can result in the intersection point jumping from a lower step (e.g., coal) on the curve to a starkly higher step (e.g., gas-fired CC).

In terms of demand changes, MRN-NEEM simulates the macroeconomic feedback loops induced by changes in the cost of energy or electricity. When energy prices increase (as under a carbon policy) more capital and labor (and possibly materials) are substituted for energy in the production of each unit of output. That is, production becomes less energy-intensive relative to the BAU case.

An analogous shift occurs within households, which can involve both the increased adoption of energy-efficient technologies and behavioral changes that result in lower overall (direct) consumption of energy services. As an economy-wide general equilibrium model, MRN is able to capture these phenomena, since it captures all economy-wide relationships, including responses to price changes (in electricity, other energy inputs, and between energy and non-energy goods and services).

The production functions in the model, including those for the energy sectors, the non-energy sectors, and the household sector, capture the impacts of rate changes on electricity demand. When energy prices increase (as under a carbon policy) more capital and labor (and possibly materials) are substituted for energy in the production of each unit of output. That is, production becomes less energy-intensive relative to the BAU case. An analogous shift occurs within households, which require less energy due to the purchase and operation of more capital-intensive (but more energy-efficient) appliances. Households may also simply reduce their demand for energy services in response higher prices. Thus, household demand-response involves both increased adoption of energy-efficient technologies and behavioral changes that result in lower overall (direct) consumption of energy services.

The price elasticity of electricity demand is not a direct input of the MRN model, but is implied. The demand elasticity depends on the elasticity of substitutions (most notably between (1) energy inputs and (2) composite energy inputs with all other inputs) and the value shares of the inputs that characterize the household consumption functions. There is a separate elasticity of substitution for the residential sector and the commercial sectors and this elasticity is time varying.<sup>23</sup>

The model's electricity demand response implies a range of demand elasticity of electricity between -0.14 to -0.17 in the short run (2015) and a range of -0.45 to -0.51 in the long run (2030). The longer-run elasticities are higher, but this is precisely because these are long-run measures – in the long-run capital is more malleable (movement of

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<sup>23</sup> 4 CSR 240-22.060(4)(C); 4 CSR 240-22.060(6)(D)

capital is less restrictive) and hence becomes more energy-efficient in response to sustained higher energy prices.

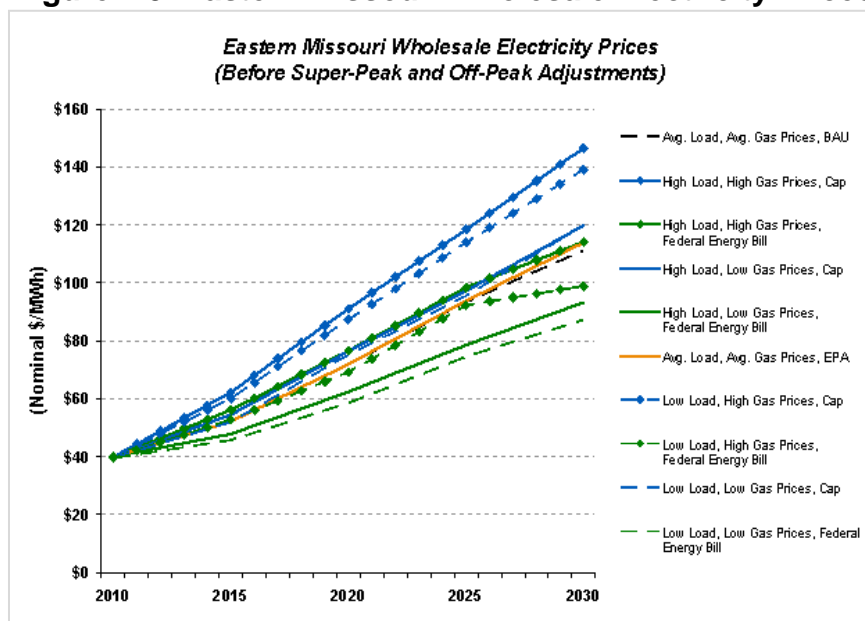
There has been much economic research on the topic of electricity demand responses to changing electricity prices. A primary source for the short-run and long-run elasticities cited above is a 2004 study by James Espey and Molly Espey (Espey 2004). In Espey 2004 the authors analyzed 36 peer-reviewed studies on residential electricity demand, which resulted in 123 estimates of short-run price elasticity and 125 estimates of long-run price elasticity. The short-run elasticity estimates ranged from -2.01 to -0.004 and had a mean of -0.35 and a median of -0.28; the long-run elasticity estimates ranged from -2.25 to -0.04 and had a mean of -0.85 and a median of -0.81.

In addition, the U.S. Department of Energy's Energy Information Administration (EIA) released a paper on price responsiveness. The paper describes the price responses of different energy inputs, including electricity, used in the EIA's Annual Energy Outlook. These price responses are based on model simulations in which the price of energy inputs were doubled.

Short-run response (response in the year of a price change and in the two following years) and long-run responses (based on 20 years following sustained price increases) were estimated for residential and commercial electricity consumers. Short-run own-price elasticity for residential electricity demand ranged from -0.20 to -0.34 and long-run own-price elasticity for residential electricity demand was -0.49. For commercial electricity demand, the short-run elasticity ranged from -0.10 to -0.20 and the long-run elasticity was -0.45.

Based on these sources and other work performed by CRA experts, the MRN-NEEM analysis calibrated the utility and production function elasticities of substitution to target a short-run elasticity of -0.20 and a long-run elasticity of -0.80.

Figure 2.14 presents all-hours wholesale electricity prices in Eastern Missouri consistent with the MRN-NEEM methodology described above.

**Figure 2.5 Eastern Missouri Wholesale Electricity Prices**

The construction of candidate resource plans on a deterministic basis requires the use of a model more local in scope at both the system and regional level. For this phase of the IRP, Ameren Missouri used MIDAS, which is a chronological model in which new build decisions are determined on a year-to-year basis. This model requires electricity prices on an hourly basis for the entirety of the planning horizon. In contrast, the MRN-NEEM model dispatches generators to a load duration curve that aggregates the 8,760 hours in a year into 20 load blocks. Therefore, Ameren Missouri used its own price shaping methodology to estimate hourly power prices using the annual power prices from the MRN-NEEM model.

### Power Price Shaping

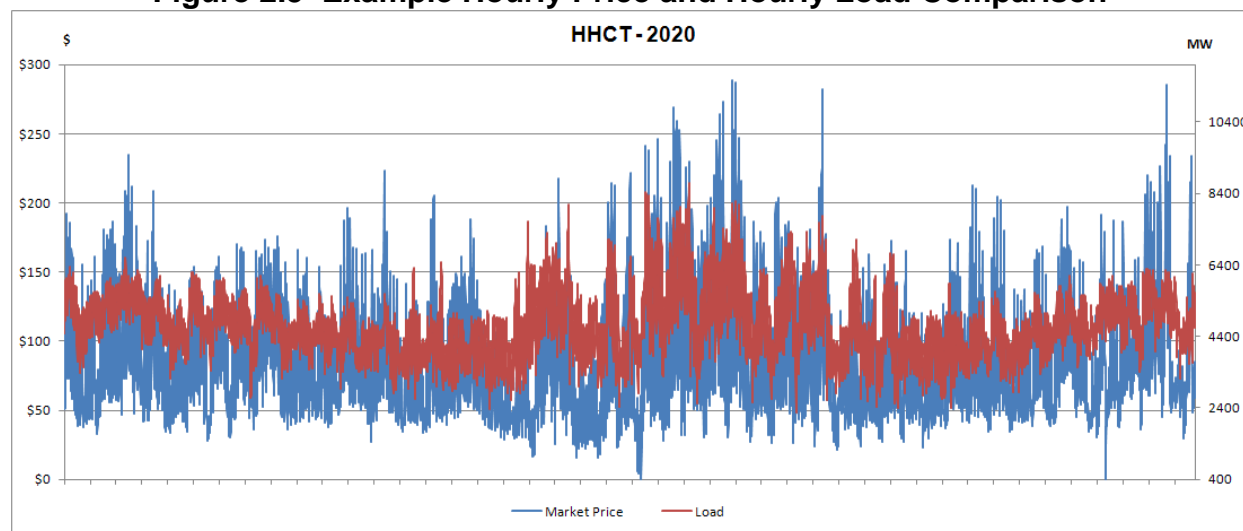
Ameren Missouri obtained the around-the-clock (ATC) prices from CRA as mentioned earlier. However, since the MIDAS model runs on an hourly basis, having only an annual market price or a few blocks for the whole year does not allow the model to dispatch the marginal unit and determine off-system sales/purchases as well as it is capable of doing. Even though it is not possible to predict market prices for each individual hour, it is important to have a reasonable representation. Therefore, Ameren Missouri has decided to use the same methodology it uses in its fuel budgeting models for creating hourly prices.

The first step in creating the hourly price shapes is estimating the monthly price blocks for each year. Ameren Missouri's budget electricity price forecast was used to estimate the 5x16, 7x8, 1x16 Saturday and 1x16 Sunday price blocks for each month. The ratio of 5x16 to ATC, 7x8 to ATC, etc., were estimated using the budget forecast to be applied to the CRA prices. The budget forecast at the time assumed a carbon tax

starting in year 2014, while four of the ten CRA scenarios (cap & trade) had a carbon tax starting in 2015, the others did not. Therefore, for the cap & trade scenarios, year 2013 ratios from the budget forecast were repeated in 2014, and then the first year when carbon tax is introduced in the budget forecast (2014) was used for the first year when carbon tax is introduced in the CRA scenarios (2015) and the remaining years of the planning horizon. For the scenarios with no CO<sub>2</sub> price, the ratios from 2013 were used for the remaining years in the planning horizon. Once the price block ratios were determined, they were multiplied by CRA's ATC prices for each year in each scenario.

The next step is estimating the price for each hour that is consistent with the monthly price blocks. For price shaping Ameren Missouri used the 2008 day-ahead prices to maintain a consistent relationship with the hourly loads. The share of each hour in the monthly price block to which it belongs is estimated in the 2008 day-ahead prices and then this ratio is applied to the respective CRA scenario price blocks estimated in the prior step. Once all the hours are estimated, the forecasted load and price shapes are examined to make sure they are consistent. Figure 2.15 shows the resulting price shapes and hourly load forecast for 2020 as an example.

**Figure 2.5 Example Hourly Price and Hourly Load Comparison**



### 2.5.9 Nuclear Fuel Price Forecasts<sup>24</sup>

Since CRA's MRN-NEEM model does not fully simulate a competitive nuclear fuel market, Ameren Missouri engaged the Ux Consulting Company (UxC).<sup>25</sup> UxC is a leading firm in the field of nuclear fuel prices, to provide a forecast of nuclear fuel prices for use in this IRP, a role they fulfilled in the 2008 IRP.<sup>26</sup>

<sup>24</sup> 4 CSR 240-22.040(9)(C)

<sup>25</sup> 4 CSR 240-22.040(8)(A)1.

<sup>26</sup> 4 CSR 240-22.040(8)(A)2.

UxC provided annual price forecasts through 2020 for uranium (U<sub>3</sub>O<sub>8</sub>), conversion (UF<sub>6</sub>), enrichment (SWU), and fabrication front-end fuel components. It used the same approaches with each of the components; however, UxC forecasted spot prices for uranium and conversion, while it forecasted base prices for new term contract for enrichment and fabrication.

The UxC price forecasts are generated by considering both market fundamentals (supply and demand) as well as an examination of short-term market behavior on the part of speculators and others that can exacerbate price trends set in motion by underlying supply and demand.<sup>27</sup>

Fundamental analysis addresses the level of prices needed to support new production as well as the supply/demand balance in the long-term market. This analysis captures the pressure placed on available long-term supplies and the degree of competition that exists for long-term contracts, which gives an indication of the relative pricing power of producers.<sup>28</sup> The fact that the published long-term price is well above marginal costs attests to the situation where a simple marginal cost price analysis does not necessarily capture the current market dynamics at any point in time.

As before, UxC continues to focus on the demand for production, which takes total requirements and nets out secondary supplies such as Highly Enriched Uranium (HEU) feed to derive the underlying need for production. Like reactor requirements, the demand for production is growing. In fact, it is growing more quickly than requirements, since the availability of inventory supplies is generally shrinking over time, and HEU feed is earmarked to disappear from the market by 2014. Also, inventory demand is growing, which has the tendency of moving requirements (and demand for production) forward in time.

UxC also focuses on the expected balance of supply and demand in the spot market, since we are forecasting a spot price for uranium and conversion. Here, the role of speculators and financial interests become more important as they can represent additional demand. Financial interests may accumulate inventories, thus adding additional supply to the spot market.

Even more so than the long-term price, the spot price can vary considerably from production costs because it is an inventory-driven price. Ultimately, spot prices are linked to a production-cost based price since an excess/shortage of production causes inventories to rise/fall, and this in turn causes changes in the spot price, which affects prices received by producers by virtue of it being referenced in long-term contracts.

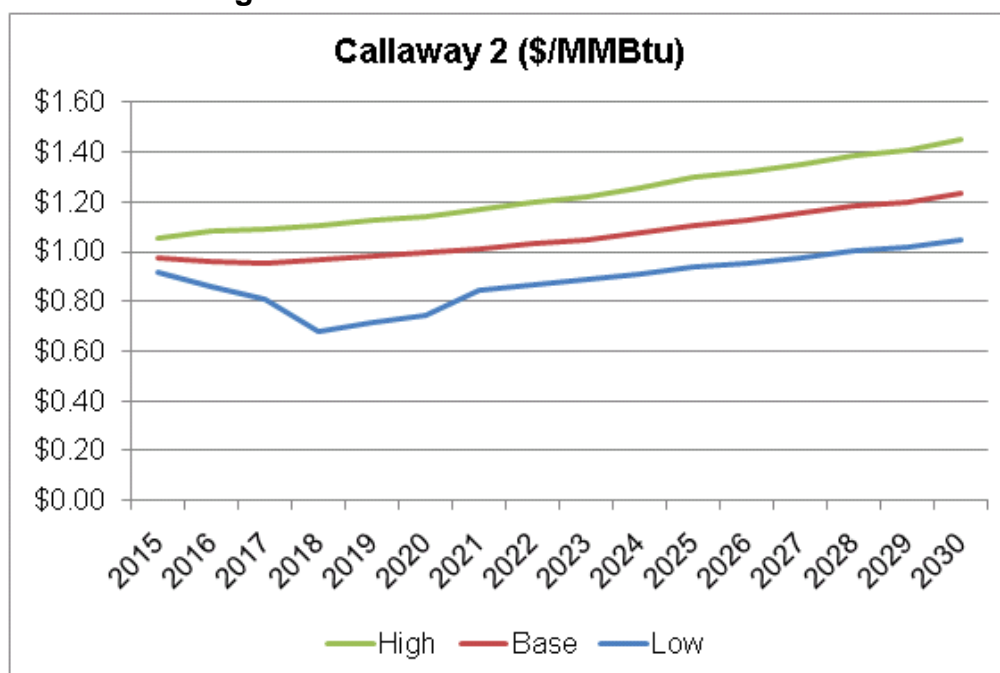
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<sup>27</sup> 4 CSR 240-22.040(8)(A)1.A.

<sup>28</sup> 4 CSR 240-22.040(8)(A)1.B.

For its uranium, conversion and enrichment forecasts, UxC provides three standard scenario forecasts: High Case, Mid Case and Low Case.<sup>29</sup> With each scenario, specific assumption sets are presented that would lead to the related price case (high, mid or low prices). An annual price range is then provided for each year representing the variance in price movement expected for that year. UxC's standard price forecasts extend through 2020. A mid-point value (simple average price) per year is also provided to aid those customers that need a single price point per year forecast. Table 2.22 contains the forecasts used for modeling both existing and new nuclear units. Figure 2.16 shows the nuclear price forecasts for a new nuclear unit.

**Figure 2.5 Nuclear Fuel Price Forecasts**



Each scenario is then assigned an individual probability basis that is related to the likelihood of the associated assumptions. The probabilities for each of the three cases add to 100%, and when each price case is multiplied by its probability and the three cases added together would result in the composite price case. The probability weighting is assigned on a year-by-year basis for uranium, while a single probability weighting is assigned for all years for conversion and enrichment. For forecast periods beyond 2020, UxC has suggested using the mid-point price level in 2020 and applying a specific escalation rate that is appropriate with either current market conditions or the client's expectations. At no point in the planning horizon is there expected to be additional restrictions on the use of nuclear fuel for the production of electricity.<sup>30</sup>

<sup>29</sup> 4 CSR 240-22.040(8)(A)3.

<sup>30</sup> 4 CSR 240-22.040(8)(A)1.G.

### *Nuclear Fuel Cycle*

Uranium comes from mined ore and the end product is a powder in a barrel. The next processing step is chemically converting that powder (U<sub>3</sub>O<sub>8</sub>) into UF<sub>6</sub>, a fluorination step. Then the UF<sub>6</sub> is enriched in the isotope U<sup>235</sup> from 0.711 wt. % in nature to between 4-5%. Due to the same technology used to make nuclear weapons, this sensitive technology is controlled by governments. Then the enriched uranium product (EUP) is sent to the metal fabrication steps where it is transformed into powder, pressed into pellets, and those pellets are inserted into long metal tubes, end plugs are welded on, and those nuclear fuel rods are inserted in a nuclear fuel assembly.

Nuclear fuel is a world-wide market since the relative cost of transportation is very small versus the cost of the enriched uranium. However, in most major international trade, trade barriers can exist from time to time that impede the commercial flow of products and services.<sup>31</sup>

Uranium is the only product, whereas conversion, enrichment, and fabrication are services. There is enough uranium in the world for the conceivable future as ore in the ground. The market supply of uranium and for these other services is more a question of how long it takes for production to expand.

Nuclear fuel cost is made up of uranium, conversion, enrichment and fabrication costs to build a fuel assembly and associated AFUDC prior to heat production. Once the assembly is in heat production, cost accumulation stops, and the cost of the assembly is amortized over the production cycles while it produces energy in the reactor. Additional costs include DOE spent fuel charges.

### *Uranium*

Uranium cost uncertainty dominates the nuclear fuel cost. Actual future prices are difficult to forecast even six months out. Three years out is a very long price forecast. While U<sub>3</sub>O<sub>8</sub> cost of production needs to be under \$50/lb. for a new project to proceed, the price can be very much different than production costs due to near term supply and demand in the spot market. There have been some relatively new entrants to the uranium market, uranium metal funds and speculators, which add to demand in rising markets and add more price uncertainty.

World-wide supply vs. demand for uranium is in relative balance from 2007-2013, but there appears to be a large supply gap after that. UxC has all known uranium production, both expansions and new mines in their forecasts. UXC believes the current price is a large motivator to bring on new projects for delivery in that time frame.

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<sup>31</sup> 4 CSR 240-22.040(8)(A)1.D.; 4 CSR 240-22.040(8)(A)1.E.

It takes three to ten years to explore for a new large uranium ore body and between five to fifteen years to build a mine to produce U<sub>3</sub>O<sub>8</sub> from ore. So it is difficult to see how the post 2013 supply gap will be filled from the marketplace. For 2011 and 2012, world-wide production expansion is not linked to price since it takes time to get new production online.

### **Conversion**

Conversion is a very small percentage of nuclear fuel costs. The industry is in a short term supply vs. demand balance. The entire industry is subject to a potential major supply disruption if one facility is closed due to acts of god or accidents. Current labor disputes at the Honeywell conversion facility in Metropolis, IL has resulted in the spot price doubling from \$6 to \$12/kg.

### **Enrichment<sup>32</sup>**

Enrichment prices are historically less volatile than uranium. The UxC forecasted prices should be sufficient to encourage new plants based upon existing centrifuge technology. While uranium and enrichment can be substituted to make EUP, and due to recently high uranium prices, that would assume more enrichment is used and less expensive uranium is used. However, enrichment plants are near capacity world-wide and it takes several years to bring new plants online, centrifuge by centrifuge, and most of that capacity is already sold.

Using Urenco centrifuge technology, the plants that are expanding or new are:

- 1) Areva current enrichment plant that is replacing its older technology,
- 2) Urenco's European enrichment plants are expanding,
- 3) Urenco's National Enrichment facility in New Mexico was recently built and has received its operating permit,
- 4) Areva's plan for a new enrichment plant in the U.S.

While most of this expansion is sold, additional expansion may become available for sale but it is not expected for deliveries prior to 2015. It is uncertain whether USEC can implement its centrifuge technology and it is also uncertain how long the existing Paducah, Kentucky DOE facility will operate.

There is an existing trade case in the U.S. that effectively limits Russian enrichment to be sold directly into the U.S. The U.S. and Russian governments have agreed to new limit of direct Russian enrichment sales into the U.S. post 2013.<sup>33</sup>

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<sup>32</sup> 4 CSR 240-22.040(8)(A)1.F.

<sup>33</sup> 4 CSR 240-22.040(8)(A)1.C.

***Fabrication***

The fabrication sector tends to be more local and static due to two reasons: 1) governments need to license the fuel design and technology, and 2) there is a high premium placed upon fuel that does not leak so more proven technology and sometimes more local technology is preferred. Fabrication is not a commodity like uranium, conversion, and enrichment. Escalation in contracts is tied to labor, electricity, and industrial commodities.

## 2.6 Supporting Tables

**Table 2.614 SO<sub>2</sub> Allowance Prices (Nominal \$/Allowance)**

|      | Avg.<br>Load,<br>Avg.<br>Gas<br>Prices,<br>BAU | High<br>Load,<br>High<br>Gas<br>Prices,<br>Cap | High<br>Load,<br>High<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill | High<br>Load,<br>Low<br>Gas<br>Prices,<br>Cap | High<br>Load,<br>Low<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill | Avg.<br>Load,<br>Avg.<br>Gas<br>Prices,<br>EPA | Low<br>Load,<br>High<br>Gas<br>Prices,<br>Cap | Low<br>Load,<br>High<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill | Low<br>Load,<br>Low<br>Gas<br>Prices,<br>Cap | Low<br>Load,<br>Low<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill |
|------|--|--|--|---|---|--|---|---|--|--|
| 2010 | \$306  | \$283  | \$271  | \$254   | \$238   | \$309  | \$274   | \$245   | \$246  | \$212  |
| 2011 | \$308  | \$285  | \$273  | \$255   | \$239   | \$311  | \$275   | \$247   | \$248  | \$213  |
| 2012 | \$310  | \$287  | \$275  | \$257   | \$241   | \$313  | \$277   | \$248   | \$249  | \$215  |
| 2013 | \$312  | \$289  | \$277  | \$259   | \$243   | \$315  | \$279   | \$250   | \$251  | \$216  |
| 2014 | \$315  | \$291  | \$278  | \$261   | \$244   | \$318  | \$281   | \$252   | \$253  | \$218  |
| 2015 | \$317  | \$292  | \$280  | \$262   | \$246   | \$320  | \$283   | \$253   | \$255  | \$219  |
| 2016 | \$347  | \$321  | \$307  | \$288   | \$270   | \$350  | \$310   | \$278   | \$279  | \$240  |
| 2017 | \$377  | \$349  | \$334  | \$313   | \$293   | \$381  | \$337   | \$302   | \$303  | \$261  |
| 2018 | \$408  | \$377  | \$361  | \$338   | \$317   | \$412  | \$364   | \$326   | \$328  | \$282  |
| 2019 | \$438  | \$405  | \$388  | \$363   | \$340   | \$442  | \$392   | \$351   | \$352  | \$303  |
| 2020 | \$469  | \$433  | \$415  | \$388   | \$364   | \$473  | \$419   | \$375   | \$377  | \$324  |
| 2021 | \$513  | \$474  | \$458  | \$426   | \$364   | \$518  | \$459   | \$376   | \$413  | \$333  |
| 2022 | \$558  | \$516  | \$492  | \$463   | \$364   | \$564  | \$499   | \$376   | \$449  | \$343  |
| 2023 | \$603  | \$557  | \$536  | \$500   | \$365   | \$609  | \$539   | \$377   | \$485  | \$352  |
| 2024 | \$648  | \$599  | \$580  | \$537   | \$365   | \$654  | \$579   | \$378   | \$521  | \$361  |
| 2025 | \$693  | \$640  | \$624  | \$575   | \$365   | \$700  | \$620   | \$379   | \$557  | \$370  |
| 2026 | \$760  | \$675  | \$650  | \$539   | \$382   | \$767  | \$633   | \$390   | \$528  | \$387  |
| 2027 | \$826  | \$710  | \$686  | \$503   | \$398   | \$834  | \$647   | \$401   | \$498  | \$403  |
| 2028 | \$893  | \$744  | \$720  | \$467   | \$414   | \$901  | \$661   | \$412   | \$469  | \$420  |
| 2029 | \$959  | \$779  | \$754  | \$431   | \$431   | \$968  | \$674   | \$423   | \$439  | \$437  |
| 2030 | \$1,026  | \$814  | \$789  | \$395   | \$447   | \$1,035  | \$688   | \$434   | \$409  | \$454  |

**Table 2.6 Annual NO<sub>x</sub> Allowance Prices (Nominal \$/Ton)**

|      | Avg.<br>Load,<br>Avg.<br>Gas<br>Prices,<br>BAU | High<br>Load,<br>High<br>Gas<br>Prices,<br>Cap | High<br>Load,<br>High<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill | High<br>Load,<br>Low<br>Gas<br>Prices,<br>Cap | High<br>Load,<br>Low<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill | Avg.<br>Load,<br>Avg.<br>Gas<br>Prices,<br>EPA | Low<br>Load,<br>High<br>Gas<br>Prices,<br>Cap | Low<br>Load,<br>High<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill | Low<br>Load,<br>Low<br>Gas<br>Prices,<br>Cap | Low<br>Load,<br>Low<br>Gas<br>Prices,<br>Federal<br>Energy<br>Bill |
|------|--|--|--|---|---|--|---|---|--|--|
| 2010 | \$823  | \$1,116  | \$878  | \$29  | \$516   | \$855  | \$606   | \$489   | \$0  | \$135  |
| 2011 | \$902  | \$1,224  | \$962  | \$32  | \$565   | \$937  | \$664   | \$536   | \$0  | \$148  |
| 2012 | \$981  | \$1,331  | \$1,046  | \$35  | \$615   | \$1,019  | \$722   | \$583   | \$0  | \$161  |
| 2013 | \$1,060  | \$1,438  | \$1,131  | \$38  | \$664   | \$1,100  | \$781   | \$630   | \$0  | \$174  |
| 2014 | \$1,139  | \$1,545  | \$1,215  | \$41  | \$713   | \$1,182  | \$839   | \$676   | \$0  | \$187  |
| 2015 | \$1,218  | \$1,652  | \$1,299  | \$44  | \$763   | \$1,264  | \$897   | \$723   | \$0  | \$200  |
| 2016 | \$1,334  | \$1,810  | \$1,423  | \$35  | \$836   | \$1,386  | \$983   | \$793   | \$0  | \$219  |
| 2017 | \$1,451  | \$1,969  | \$1,548  | \$26  | \$909   | \$1,507  | \$1,069                                       | \$862   | \$0  | \$238  |
| 2018 | \$1,568  | \$2,127  | \$1,673  | \$17  | \$982   | \$1,628  | \$1,155                                       | \$931   | \$0  | \$257  |
| 2019 | \$1,685  | \$2,286  | \$1,797  | \$9   | \$1,056   | \$1,750  | \$1,241                                       | \$1,001   | \$0  | \$276  |
| 2020 | \$1,802  | \$2,444  | \$1,922  | \$0   | \$1,129   | \$1,871  | \$1,327                                       | \$1,070   | \$0  | \$295  |
| 2021 | \$1,974  | \$2,678  | \$1,673  | \$0   | \$1,031   | \$2,050  | \$1,454                                       | \$1,094   | \$0  | \$324  |
| 2022 | \$2,147  | \$2,913  | \$1,423  | \$0   | \$934   | \$2,230  | \$1,582                                       | \$1,118   | \$0  | \$352  |
| 2023 | \$2,320  | \$3,147  | \$1,174  | \$0   | \$837   | \$2,409  | \$1,709                                       | \$1,141   | \$0  | \$381  |
| 2024 | \$2,493  | \$3,382  | \$925  | \$0   | \$739   | \$2,589  | \$1,836                                       | \$1,165   | \$0  | \$409  |
| 2025 | \$2,665  | \$3,616  | \$675  | \$0   | \$642   | \$2,768  | \$1,963                                       | \$1,188   | \$0  | \$437  |
| 2026 | \$2,774  | \$3,229  | \$740  | \$0   | \$704   | \$2,973  | \$1,571                                       | \$985   | \$0  | \$479  |
| 2027 | \$2,883  | \$2,841  | \$805  | \$0   | \$765   | \$3,179  | \$1,178                                       | \$782   | \$0  | \$521  |
| 2028 | \$2,991  | \$2,454  | \$869  | \$0   | \$827   | \$3,384  | \$785   | \$578   | \$0  | \$563  |
| 2029 | \$3,100  | \$2,067  | \$934  | \$0   | \$888   | \$3,589  | \$393   | \$375   | \$0  | \$605  |
| 2030 | \$3,209  | \$1,680  | \$999  | \$0   | \$950   | \$3,795  | \$0   | \$171   | \$0  | \$647  |

**Table 2.6 Henry Hub Natural Gas Prices (Nominal \$/MMBtu)**

|      | Avg. Load, Avg. Gas Prices, BAU | High Load, High Gas Prices, Cap | High Load, High Gas Prices, Energy Bill | High Load, Low Gas Prices, Cap | High Load, Low Gas Prices, Energy Bill | Avg. Load, Avg. Gas Prices, EPA | Low Load, High Gas Prices, Cap | Low Load, High Gas Prices, Energy Bill | Low Load, Low Gas Prices, Cap | Low Load, Low Gas Prices, Energy Bill |
|------|---------------------------------|---------------------------------|---|--------------------------------|--|---------------------------------|--------------------------------|--|-------------------------------|---------------------------------------|
| 2010 | \$5.96                          | \$5.97                          | \$5.97                                  | \$6.01                         | \$6.04                                 | \$5.97                          | \$5.98                         | \$5.97                                 | \$6.00                        | \$5.99                                |
| 2011 | \$6.33                          | \$6.54                          | \$6.50                                  | \$6.25                         | \$6.22                                 | \$6.35                          | \$6.54                         | \$6.48                                 | \$6.21                        | \$6.15                                |
| 2012 | \$6.71                          | \$7.12                          | \$7.02                                  | \$6.49                         | \$6.41                                 | \$6.72                          | \$7.11                         | \$7.00                                 | \$6.42                        | \$6.32                                |
| 2013 | \$7.08                          | \$7.70                          | \$7.55                                  | \$6.72                         | \$6.59                                 | \$7.10                          | \$7.67                         | \$7.52                                 | \$6.63                        | \$6.49                                |
| 2014 | \$7.46                          | \$8.27                          | \$8.07                                  | \$6.96                         | \$6.78                                 | \$7.48                          | \$8.23                         | \$8.04                                 | \$6.84                        | \$6.65                                |
| 2015 | \$7.83                          | \$8.85                          | \$8.60                                  | \$7.20                         | \$6.97                                 | \$7.85                          | \$8.80                         | \$8.56                                 | \$7.05                        | \$6.82                                |
| 2016 | \$8.29                          | \$9.38                          | \$9.11                                  | \$7.51                         | \$7.25                                 | \$8.31                          | \$9.34                         | \$9.06                                 | \$7.39                        | \$7.14                                |
| 2017 | \$8.74                          | \$9.91                          | \$9.62                                  | \$7.83                         | \$7.54                                 | \$8.76                          | \$9.88                         | \$9.56                                 | \$7.73                        | \$7.47                                |
| 2018 | \$9.20                          | \$10.45                         | \$10.13                                 | \$8.14                         | \$7.83                                 | \$9.21                          | \$10.41                        | \$10.06                                | \$8.07                        | \$7.80                                |
| 2019 | \$9.65                          | \$10.98                         | \$10.64                                 | \$8.46                         | \$8.12                                 | \$9.67                          | \$10.95                        | \$10.55                                | \$8.42                        | \$8.13                                |
| 2020 | \$10.11                         | \$11.51                         | \$11.15                                 | \$8.77                         | \$8.41                                 | \$10.12                         | \$11.49                        | \$11.05                                | \$8.76                        | \$8.46                                |
| 2021 | \$10.66                         | \$12.18                         | \$11.79                                 | \$9.21                         | \$8.82                                 | \$10.68                         | \$12.13                        | \$11.69                                | \$9.18                        | \$8.85                                |
| 2022 | \$11.22                         | \$12.85                         | \$12.43                                 | \$9.65                         | \$9.23                                 | \$11.24                         | \$12.76                        | \$12.32                                | \$9.61                        | \$9.24                                |
| 2023 | \$11.77                         | \$13.53                         | \$13.07                                 | \$10.09                        | \$9.64                                 | \$11.80                         | \$13.40                        | \$12.96                                | \$10.03                       | \$9.63                                |
| 2024 | \$12.33                         | \$14.20                         | \$13.71                                 | \$10.52                        | \$10.05                                | \$12.36                         | \$14.03                        | \$13.59                                | \$10.45                       | \$10.02                               |
| 2025 | \$12.88                         | \$14.87                         | \$14.35                                 | \$10.96                        | \$10.46                                | \$12.92                         | \$14.67                        | \$14.23                                | \$10.88                       | \$10.41                               |
| 2026 | \$13.31                         | \$15.32                         | \$14.80                                 | \$11.23                        | \$10.78                                | \$13.36                         | \$15.13                        | \$14.68                                | \$11.21                       | \$10.79                               |
| 2027 | \$13.73                         | \$15.76                         | \$15.24                                 | \$11.51                        | \$11.10                                | \$13.80                         | \$15.58                        | \$15.13                                | \$11.53                       | \$11.18                               |
| 2028 | \$14.15                         | \$16.20                         | \$15.69                                 | \$11.78                        | \$11.42                                | \$14.24                         | \$16.04                        | \$15.58                                | \$11.86                       | \$11.56                               |
| 2029 | \$14.57                         | \$16.65                         | \$16.14                                 | \$12.05                        | \$11.74                                | \$14.68                         | \$16.50                        | \$16.03                                | \$12.18                       | \$11.94                               |
| 2030 | \$14.99                         | \$17.09                         | \$16.58                                 | \$12.33                        | \$12.06                                | \$15.13                         | \$16.95                        | \$16.48                                | \$12.51                       | \$12.32                               |

**Table 2.6 Minemouth Coal Prices for High-Sulfur Coals in the Illinois Basin (Nominal \$/MMBtu)**

|      | Avg. Load, Avg. Gas Prices, BAU | High Load, High Gas Prices, Cap | High Load, High Gas Prices, Energy Bill | High Load, Low Gas Prices, Cap | High Load, Low Gas Prices, Energy Bill | Avg. Load, Avg. Gas Prices, EPA | Low Load, High Gas Prices, Cap | Low Load, High Gas Prices, Energy Bill | Low Load, Low Gas Prices, Cap | Low Load, Low Gas Prices, Energy Bill |
|------|---------------------------------|---------------------------------|---|--------------------------------|--|---------------------------------|--------------------------------|--|-------------------------------|---------------------------------------|
| 2010 | \$2.29                          | \$2.30                          | \$2.33                                  | \$2.37                         | \$2.39                                 | \$2.29                          | \$2.32                         | \$2.35                                 | \$2.35                        | \$2.37                                |
| 2011 | \$2.44                          | \$2.45                          | \$2.47                                  | \$2.47                         | \$2.50                                 | \$2.43                          | \$2.45                         | \$2.48                                 | \$2.44                        | \$2.49                                |
| 2012 | \$2.58                          | \$2.59                          | \$2.61                                  | \$2.57                         | \$2.61                                 | \$2.57                          | \$2.58                         | \$2.61                                 | \$2.53                        | \$2.60                                |
| 2013 | \$2.72                          | \$2.73                          | \$2.75                                  | \$2.67                         | \$2.73                                 | \$2.71                          | \$2.72                         | \$2.74                                 | \$2.62                        | \$2.71                                |
| 2014 | \$2.87                          | \$2.87                          | \$2.88                                  | \$2.77                         | \$2.84                                 | \$2.86                          | \$2.85                         | \$2.87                                 | \$2.70                        | \$2.82                                |
| 2015 | \$3.01                          | \$3.01                          | \$3.02                                  | \$2.87                         | \$2.96                                 | \$3.00                          | \$2.98                         | \$3.00                                 | \$2.79                        | \$2.93                                |
| 2016 | \$3.06                          | \$2.98                          | \$3.04                                  | \$2.80                         | \$2.94                                 | \$3.04                          | \$2.94                         | \$2.97                                 | \$2.74                        | \$2.90                                |
| 2017 | \$3.11                          | \$2.96                          | \$3.05                                  | \$2.72                         | \$2.92                                 | \$3.09                          | \$2.89                         | \$2.94                                 | \$2.69                        | \$2.86                                |
| 2018 | \$3.16                          | \$2.93                          | \$3.06                                  | \$2.64                         | \$2.90                                 | \$3.14                          | \$2.84                         | \$2.91                                 | \$2.65                        | \$2.83                                |
| 2019 | \$3.20                          | \$2.90                          | \$3.07                                  | \$2.56                         | \$2.88                                 | \$3.19                          | \$2.80                         | \$2.88                                 | \$2.60                        | \$2.80                                |
| 2020 | \$3.25                          | \$2.88                          | \$3.08                                  | \$2.48                         | \$2.86                                 | \$3.24                          | \$2.75                         | \$2.85                                 | \$2.55                        | \$2.77                                |
| 2021 | \$3.18                          | \$2.87                          | \$3.04                                  | \$2.53                         | \$2.86                                 | \$3.17                          | \$2.77                         | \$2.85                                 | \$2.58                        | \$2.79                                |
| 2022 | \$3.11                          | \$2.86                          | \$2.99                                  | \$2.58                         | \$2.87                                 | \$3.09                          | \$2.78                         | \$2.85                                 | \$2.61                        | \$2.80                                |
| 2023 | \$3.04                          | \$2.86                          | \$2.95                                  | \$2.62                         | \$2.87                                 | \$3.02                          | \$2.79                         | \$2.85                                 | \$2.65                        | \$2.82                                |
| 2024 | \$2.97                          | \$2.85                          | \$2.90                                  | \$2.67                         | \$2.88                                 | \$2.95                          | \$2.81                         | \$2.86                                 | \$2.68                        | \$2.84                                |
| 2025 | \$2.90                          | \$2.84                          | \$2.86                                  | \$2.72                         | \$2.88                                 | \$2.88                          | \$2.82                         | \$2.86                                 | \$2.72                        | \$2.86                                |
| 2026 | \$3.01                          | \$2.92                          | \$2.96                                  | \$2.75                         | \$2.98                                 | \$2.96                          | \$2.90                         | \$2.95                                 | \$2.75                        | \$2.95                                |
| 2027 | \$3.12                          | \$3.01                          | \$3.06                                  | \$2.78                         | \$3.09                                 | \$3.05                          | \$2.98                         | \$3.04                                 | \$2.78                        | \$3.04                                |
| 2028 | \$3.22                          | \$3.09                          | \$3.16                                  | \$2.81                         | \$3.19                                 | \$3.13                          | \$3.06                         | \$3.13                                 | \$2.81                        | \$3.13                                |
| 2029 | \$3.33                          | \$3.17                          | \$3.26                                  | \$2.84                         | \$3.30                                 | \$3.21                          | \$3.13                         | \$3.23                                 | \$2.84                        | \$3.23                                |
| 2030 | \$3.44                          | \$3.25                          | \$3.36                                  | \$2.87                         | \$3.40                                 | \$3.30                          | \$3.21                         | \$3.32                                 | \$2.87                        | \$3.32                                |

**Table 2.6 Minemouth Coal Prices for Northern Wyoming Powder River Basin Coals (Nominal \$/MMBtu)**

|      | Avg. Load, Avg. Gas Prices, BAU | High Load, High Gas Prices, Cap | High Load, High Gas Prices, Federal Energy Bill | High Load, Low Gas Prices, Cap | High Load, Low Gas Prices, Federal Energy Bill | Avg. Load, Avg. Gas Prices, EPA | Low Load, High Gas Prices, Cap | Low Load, High Gas Prices, Federal Energy Bill | Low Load, Low Gas Prices, Cap | Low Load, Low Gas Prices, Federal Energy Bill |
|------|---------------------------------|---------------------------------|---|--------------------------------|--|---------------------------------|--------------------------------|--|-------------------------------|---|
| 2010 | \$0.49                          | \$0.49                          | \$0.49  | \$0.49                         | \$0.49   | \$0.49                          | \$0.49                         | \$0.49   | \$0.49                        | \$0.49  |
| 2011 | \$0.52                          | \$0.50                          | \$0.52  | \$0.50                         | \$0.50   | \$0.50                          | \$0.50                         | \$0.50   | \$0.50                        | \$0.50  |
| 2012 | \$0.55                          | \$0.51                          | \$0.55  | \$0.51                         | \$0.51   | \$0.51                          | \$0.51                         | \$0.51   | \$0.51                        | \$0.51  |
| 2013 | \$0.58                          | \$0.52                          | \$0.58  | \$0.52                         | \$0.52   | \$0.52                          | \$0.52                         | \$0.52   | \$0.52                        | \$0.52  |
| 2014 | \$0.61                          | \$0.53                          | \$0.61  | \$0.53                         | \$0.53   | \$0.53                          | \$0.53                         | \$0.53   | \$0.53                        | \$0.53  |
| 2015 | \$0.64                          | \$0.54                          | \$0.64  | \$0.54                         | \$0.54   | \$0.54                          | \$0.54                         | \$0.54   | \$0.54                        | \$0.54  |
| 2016 | \$0.69                          | \$0.59                          | \$0.69  | \$0.59                         | \$0.59   | \$0.59                          | \$0.59                         | \$0.59   | \$0.59                        | \$0.59  |
| 2017 | \$0.75                          | \$0.64                          | \$0.75  | \$0.64                         | \$0.64   | \$0.64                          | \$0.64                         | \$0.64   | \$0.64                        | \$0.64  |
| 2018 | \$0.80                          | \$0.69                          | \$0.80  | \$0.69                         | \$0.69   | \$0.69                          | \$0.69                         | \$0.69   | \$0.69                        | \$0.69  |
| 2019 | \$0.86                          | \$0.74                          | \$0.86  | \$0.74                         | \$0.74   | \$0.74                          | \$0.74                         | \$0.74   | \$0.74                        | \$0.74  |
| 2020 | \$0.91                          | \$0.79                          | \$0.91  | \$0.79                         | \$0.79   | \$0.79                          | \$0.79                         | \$0.79   | \$0.79                        | \$0.79  |
| 2021 | \$0.97                          | \$0.83                          | \$0.93  | \$0.83                         | \$0.83   | \$0.83                          | \$0.83                         | \$0.83   | \$0.83                        | \$0.83  |
| 2022 | \$1.02                          | \$0.88                          | \$0.96  | \$0.88                         | \$0.88   | \$0.88                          | \$0.88                         | \$0.88   | \$0.88                        | \$0.88  |
| 2023 | \$1.08                          | \$0.93                          | \$0.98  | \$0.93                         | \$0.93   | \$0.93                          | \$0.93                         | \$0.93   | \$0.93                        | \$0.93  |
| 2024 | \$1.13                          | \$0.97                          | \$1.00  | \$0.97                         | \$0.97   | \$0.97                          | \$0.97                         | \$0.97   | \$0.97                        | \$0.97  |
| 2025 | \$1.18                          | \$1.02                          | \$1.02  | \$1.02                         | \$1.02   | \$1.02                          | \$1.02                         | \$1.02   | \$1.02                        | \$1.02  |
| 2026 | \$1.31                          | \$1.09                          | \$1.13  | \$1.09                         | \$1.09   | \$1.09                          | \$1.09                         | \$1.09   | \$1.09                        | \$1.09  |
| 2027 | \$1.43                          | \$1.15                          | \$1.25  | \$1.15                         | \$1.15   | \$1.15                          | \$1.15                         | \$1.15   | \$1.15                        | \$1.15  |
| 2028 | \$1.55                          | \$1.22                          | \$1.36  | \$1.22                         | \$1.22   | \$1.22                          | \$1.22                         | \$1.22   | \$1.22                        | \$1.22  |
| 2029 | \$1.67                          | \$1.29                          | \$1.47  | \$1.29                         | \$1.29   | \$1.29                          | \$1.29                         | \$1.29   | \$1.29                        | \$1.29  |
| 2030 | \$1.80                          | \$1.35                          | \$1.58  | \$1.35                         | \$1.35   | \$1.35                          | \$1.35                         | \$1.35   | \$1.35                        | \$1.35  |

**Table 2.6 Minemouth Coal Prices for Southern Wyoming Powder River Basin Coals (Nominal \$/MMBtu)**

|      | Avg. Load, Avg. Gas Prices, BAU | High Load, High Gas Prices, Cap | High Load, High Gas Prices, Federal Energy Bill | High Load, Low Gas Prices, Cap | High Load, Low Gas Prices, Federal Energy Bill | Avg. Load, Avg. Gas Prices, EPA | Low Load, High Gas Prices, Cap | Low Load, High Gas Prices, Federal Energy Bill | Low Load, Low Gas Prices, Cap | Low Load, Low Gas Prices, Federal Energy Bill |
|------|---------------------------------|---------------------------------|---|--------------------------------|--|---------------------------------|--------------------------------|--|-------------------------------|---|
| 2010 | \$0.49                          | \$0.49                          | \$0.49  | \$0.49                         | \$0.49   | \$0.49                          | \$0.49                         | \$0.49   | \$0.49                        | \$0.49  |
| 2011 | \$0.51                          | \$0.50                          | \$0.50  | \$0.50                         | \$0.50   | \$0.50                          | \$0.50                         | \$0.50   | \$0.50                        | \$0.50  |
| 2012 | \$0.52                          | \$0.51                          | \$0.51  | \$0.51                         | \$0.51   | \$0.52                          | \$0.51                         | \$0.51   | \$0.51                        | \$0.51  |
| 2013 | \$0.54                          | \$0.52                          | \$0.52  | \$0.52                         | \$0.52   | \$0.53                          | \$0.52                         | \$0.52   | \$0.52                        | \$0.52  |
| 2014 | \$0.55                          | \$0.53                          | \$0.53  | \$0.53                         | \$0.53   | \$0.54                          | \$0.53                         | \$0.53   | \$0.53                        | \$0.53  |
| 2015 | \$0.57                          | \$0.54                          | \$0.54  | \$0.54                         | \$0.54   | \$0.56                          | \$0.54                         | \$0.54   | \$0.54                        | \$0.54  |
| 2016 | \$0.61                          | \$0.59                          | \$0.59  | \$0.59                         | \$0.59   | \$0.60                          | \$0.59                         | \$0.59   | \$0.59                        | \$0.59  |
| 2017 | \$0.66                          | \$0.64                          | \$0.64  | \$0.64                         | \$0.64   | \$0.65                          | \$0.64                         | \$0.64   | \$0.64                        | \$0.64  |
| 2018 | \$0.70                          | \$0.69                          | \$0.69  | \$0.69                         | \$0.69   | \$0.69                          | \$0.69                         | \$0.69   | \$0.69                        | \$0.69  |
| 2019 | \$0.74                          | \$0.74                          | \$0.74  | \$0.74                         | \$0.74   | \$0.74                          | \$0.74                         | \$0.74   | \$0.74                        | \$0.74  |
| 2020 | \$0.79                          | \$0.79                          | \$0.79  | \$0.79                         | \$0.79   | \$0.79                          | \$0.79                         | \$0.79   | \$0.79                        | \$0.79  |
| 2021 | \$0.83                          | \$0.83                          | \$0.83  | \$0.83                         | \$0.83   | \$0.83                          | \$0.83                         | \$0.83   | \$0.83                        | \$0.83  |
| 2022 | \$0.88                          | \$0.88                          | \$0.88  | \$0.88                         | \$0.88   | \$0.88                          | \$0.88                         | \$0.88   | \$0.88                        | \$0.88  |
| 2023 | \$0.93                          | \$0.93                          | \$0.93  | \$0.93                         | \$0.93   | \$0.93                          | \$0.93                         | \$0.93   | \$0.93                        | \$0.93  |
| 2024 | \$0.97                          | \$0.97                          | \$0.97  | \$0.97                         | \$0.97   | \$0.97                          | \$0.97                         | \$0.97   | \$0.97                        | \$0.97  |
| 2025 | \$1.02                          | \$1.02                          | \$1.02  | \$1.02                         | \$1.02   | \$1.02                          | \$1.02                         | \$1.02   | \$1.02                        | \$1.02  |
| 2026 | \$1.09                          | \$1.09                          | \$1.09  | \$1.09                         | \$1.09   | \$1.09                          | \$1.09                         | \$1.09   | \$1.09                        | \$1.09  |
| 2027 | \$1.15                          | \$1.15                          | \$1.15  | \$1.15                         | \$1.15   | \$1.15                          | \$1.15                         | \$1.15   | \$1.15                        | \$1.15  |
| 2028 | \$1.22                          | \$1.22                          | \$1.22  | \$1.22                         | \$1.22   | \$1.22                          | \$1.22                         | \$1.22   | \$1.22                        | \$1.22  |
| 2029 | \$1.29                          | \$1.29                          | \$1.29  | \$1.29                         | \$1.29   | \$1.29                          | \$1.29                         | \$1.29   | \$1.29                        | \$1.29  |
| 2030 | \$1.35                          | \$1.35                          | \$1.35  | \$1.35                         | \$1.35   | \$1.35                          | \$1.35                         | \$1.35   | \$1.35                        | \$1.35  |

**Table 2.6 Coal Delivery Prices (Nominal \$/MMBtu)**

|      | New Unit | Labadie | Meramec | Rush Island | Sioux PRB | Sioux IL |
|------|----------|---------|---------|-------------|-----------|----------|
| 2010 | \$1.01   | \$0.81  | \$1.20  | \$1.28      | \$1.15    | \$0.57   |
| 2011 | \$1.06   | \$0.83  | \$1.24  | \$1.33      | \$1.18    | \$0.59   |
| 2012 | \$1.29   | \$1.24  | \$1.30  | \$1.39      | \$1.24    | \$0.62   |
| 2013 | \$1.39   | \$1.36  | \$1.43  | \$1.45      | \$1.29    | \$0.65   |
| 2014 | \$1.45   | \$1.43  | \$1.50  | \$1.52      | \$1.35    | \$0.69   |
| 2015 | \$1.50   | \$1.48  | \$1.56  | \$1.58      | \$1.40    | \$0.71   |
| 2016 | \$1.57   | \$1.54  | \$1.62  | \$1.64      | \$1.46    | \$0.74   |
| 2017 | \$1.63   | \$1.60  | \$1.69  | \$1.70      | \$1.51    | \$0.77   |
| 2018 | \$1.69   | \$1.67  | \$1.76  | \$1.77      | \$1.57    | \$0.80   |
| 2019 | \$1.76   | \$1.73  | \$1.83  | \$1.84      | \$1.64    | \$0.83   |
| 2020 | \$1.83   | \$1.80  | \$1.90  | \$1.92      | \$1.70    | \$0.87   |
| 2021 | \$1.90   | \$1.88  | \$1.98  | \$1.99      | \$1.77    | \$0.90   |
| 2022 | \$1.98   | \$1.95  | \$2.06  | \$2.07      | \$1.84    | \$0.94   |
| 2023 | \$2.06   | \$2.03  | \$2.14  | \$2.16      | \$1.92    | \$0.98   |
| 2024 | \$2.14   | \$2.11  | \$2.22  | \$2.24      | \$1.99    | \$1.02   |
| 2025 | \$2.23   | \$2.19  | \$2.31  | \$2.33      | \$2.07    | \$1.06   |
| 2026 | \$2.32   | \$2.28  | \$2.40  | \$2.43      | \$2.15    | \$1.10   |
| 2027 | \$2.41   | \$2.37  | \$2.50  | \$2.52      | \$2.24    | \$1.14   |
| 2028 | \$2.51   | \$2.47  | \$2.60  | \$2.62      | \$2.33    | \$1.19   |
| 2029 | \$2.61   | \$2.57  | \$2.71  | \$2.73      | \$2.42    | \$1.24   |
| 2030 | \$2.71   | \$2.67  | \$2.81  | \$2.84      | \$2.52    | \$1.28   |

**Table 2.6 Wholesale Electricity Prices in Eastern Missouri (Nominal \$/MWh)**

|      | Avg. Load, Avg. Gas Prices, BAU | High Load, High Gas Prices, Cap | High Load, High Gas Prices, Federal Energy Bill | High Load, Low Gas Prices, Cap | High Load, Low Gas Prices, Federal Energy Bill | Avg. Load, Avg. Gas Prices, EPA | Low Load, High Gas Prices, Cap | Low Load, High Gas Prices, Federal Energy Bill | Low Load, Low Gas Prices, Cap | Low Load, Low Gas Prices, Federal Energy Bill |
|------|---------------------------------|---------------------------------|---|--------------------------------|--|---------------------------------|--------------------------------|--|-------------------------------|---|
| 2010 | \$40                            | \$40                            | \$40  | \$39                           | \$40   | \$40                            | \$40                           | \$40   | \$39                          | \$39  |
| 2011 | \$42                            | \$44                            | \$43  | \$42                           | \$41   | \$42                            | \$44                           | \$42   | \$42                          | \$41  |
| 2012 | \$45                            | \$49                            | \$46  | \$45                           | \$43   | \$45                            | \$48                           | \$45   | \$44                          | \$42  |
| 2013 | \$47                            | \$53                            | \$50  | \$48                           | \$45   | \$47                            | \$52                           | \$48   | \$47                          | \$43  |
| 2014 | \$49                            | \$58                            | \$53  | \$51                           | \$46   | \$50                            | \$56                           | \$50   | \$49                          | \$44  |
| 2015 | \$52                            | \$62                            | \$56  | \$54                           | \$48   | \$52                            | \$60                           | \$53   | \$52                          | \$46  |
| 2016 | \$56                            | \$68                            | \$60  | \$59                           | \$51   | \$56                            | \$66                           | \$56   | \$57                          | \$48  |
| 2017 | \$60                            | \$74                            | \$64  | \$63                           | \$54   | \$60                            | \$71                           | \$59   | \$61                          | \$51  |
| 2018 | \$64                            | \$80                            | \$68  | \$68                           | \$57   | \$64                            | \$76                           | \$63   | \$66                          | \$53  |
| 2019 | \$68                            | \$85                            | \$72  | \$72                           | \$59   | \$68                            | \$82                           | \$66   | \$71                          | \$56  |
| 2020 | \$72                            | \$91                            | \$77  | \$76                           | \$62   | \$72                            | \$87                           | \$69   | \$75                          | \$58  |
| 2021 | \$76                            | \$97                            | \$81  | \$81                           | \$66   | \$76                            | \$93                           | \$74   | \$79                          | \$62  |
| 2022 | \$80                            | \$102                           | \$85  | \$85                           | \$69   | \$81                            | \$98                           | \$78   | \$83                          | \$65  |
| 2023 | \$85                            | \$107                           | \$90  | \$89                           | \$72   | \$85                            | \$103                          | \$83   | \$87                          | \$68  |
| 2024 | \$89                            | \$113                           | \$94  | \$93                           | \$75   | \$89                            | \$109                          | \$88   | \$91                          | \$71  |
| 2025 | \$93                            | \$118                           | \$98  | \$97                           | \$79   | \$94                            | \$114                          | \$92   | \$95                          | \$74  |
| 2026 | \$97                            | \$124                           | \$101   | \$102                          | \$81   | \$98                            | \$119                          | \$94   | \$100                         | \$77  |
| 2027 | \$100                           | \$130                           | \$105   | \$106                          | \$84   | \$102                           | \$124                          | \$95   | \$105                         | \$80  |
| 2028 | \$104                           | \$135                           | \$108   | \$111                          | \$87   | \$106                           | \$129                          | \$96   | \$110                         | \$82  |
| 2029 | \$108                           | \$141                           | \$111   | \$115                          | \$90   | \$110                           | \$134                          | \$98   | \$115                         | \$85  |
| 2030 | \$111                           | \$146                           | \$114   | \$120                          | \$93   | \$114                           | \$139                          | \$99   | \$120                         | \$87  |

**Table 2.6 Nuclear Fuel Prices (Nominal \$/MMBtu)**

|      | Callaway 1 |        |        | Callaway 2 |        |        |
|------|------------|--------|--------|------------|--------|--------|
|      | Low        | Base   | High   | Low        | Base   | High   |
| 2010 | \$0.69     | \$0.69 | \$0.69 | \$0.00     | \$0.00 | \$0.00 |
| 2011 | \$0.76     | \$0.76 | \$0.76 | \$0.00     | \$0.00 | \$0.00 |
| 2012 | \$0.85     | \$0.86 | \$0.87 | \$0.00     | \$0.00 | \$0.00 |
| 2013 | \$0.88     | \$0.89 | \$0.92 | \$0.00     | \$0.00 | \$0.00 |
| 2014 | \$0.89     | \$0.91 | \$0.95 | \$0.00     | \$0.00 | \$0.00 |
| 2015 | \$0.89     | \$0.93 | \$0.99 | \$0.92     | \$0.98 | \$1.06 |
| 2016 | \$0.90     | \$0.96 | \$1.04 | \$0.86     | \$0.96 | \$1.08 |
| 2017 | \$0.90     | \$0.98 | \$1.06 | \$0.81     | \$0.96 | \$1.09 |
| 2018 | \$0.91     | \$1.01 | \$1.11 | \$0.68     | \$0.96 | \$1.11 |
| 2019 | \$0.94     | \$1.06 | \$1.17 | \$0.71     | \$0.98 | \$1.13 |
| 2020 | \$0.96     | \$1.08 | \$1.20 | \$0.75     | \$1.00 | \$1.14 |
| 2021 | \$1.00     | \$1.13 | \$1.26 | \$0.84     | \$1.01 | \$1.17 |
| 2022 | \$1.04     | \$1.17 | \$1.31 | \$0.87     | \$1.03 | \$1.20 |
| 2023 | \$1.06     | \$1.20 | \$1.35 | \$0.89     | \$1.05 | \$1.22 |
| 2024 | \$1.12     | \$1.27 | \$1.43 | \$0.91     | \$1.08 | \$1.26 |
| 2025 | \$1.14     | \$1.31 | \$1.49 | \$0.94     | \$1.11 | \$1.30 |
| 2026 | \$1.16     | \$1.34 | \$1.53 | \$0.95     | \$1.13 | \$1.32 |
| 2027 | \$1.20     | \$1.39 | \$1.61 | \$0.98     | \$1.16 | \$1.35 |
| 2028 | \$1.16     | \$1.36 | \$1.58 | \$1.00     | \$1.18 | \$1.39 |
| 2029 | \$1.14     | \$1.34 | \$1.55 | \$1.02     | \$1.20 | \$1.41 |
| 2030 | \$1.09     | \$1.28 | \$1.49 | \$1.04     | \$1.24 | \$1.45 |

## 2.7 Compliance References

|  |                |
|--|----------------|
| 4 CSR 240-22.040(8)(A)1. ....                      | 7, 37          |
| 4 CSR 240-22.040(8)(A)1.A. ....                    | 23, 38         |
| 4 CSR 240-22.040(8)(A)1.B. ....                    | 17, 23, 38     |
| 4 CSR 240-22.040(8)(A)1.C. ....                    | 18, 24, 41     |
| 4 CSR 240-22.040(8)(A)1.D. ....                    | 18, 24, 40     |
| 4 CSR 240-22.040(8)(A)1.E. ....                    | 24, 40         |
| 4 CSR 240-22.040(8)(A)1.F. ....                    | 41             |
| 4 CSR 240-22.040(8)(A)1.G. ....                    | 19, 24, 39     |
| 4 CSR 240-22.040(8)(A)1-3. ....                    | 15             |
| 4 CSR 240-22.040(8)(A)2. ....                      | 19, 25, 37     |
| 4 CSR 240-22.040(8)(A)3. ....                      | 22, 39         |
| 4 CSR 240-22.040(8)(D)1. ....                      | 7              |
| 4 CSR 240-22.040(8)(D)1-2. ....                    | 25             |
| 4 CSR 240-22.040(8)(D)2. ....                      | 3              |
| 4 CSR 240-22.040(9)(C) ....                        | 15, 19, 25, 37 |
| 4 CSR 240-22.050(2) ....                           | 31             |
| 4 CSR 240-22.060(4)(C) ....                        | 34             |
| 4 CSR 240-22.060(6)(D) ....                        | 34             |
| 4 CSR 240-22.070(1) ....                           | 7              |
| 4 CSR 240-22.070(11)(A)2. ....                     | 2              |
| 4 CSR 240-22.070(2) ....                           | 2, 3, 7        |
| 4 CSR 240-22.070(3) ....                           | 7              |
| 4 CSR 240-22.070(4) ....                           | 7              |
| EO-2007-0409 – Stipulation and Agreement #35. .... | 3              |