Public

Integrated Resource Plan

4 CSR 240-22.040

Supply-Side Resource Analysis

Volume 3

February 2008

4 CSR 240-22.040 (8)

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

4 CSR 240-22.040 (8) (A)

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

1. **Fuel price forecasts shall be obtained from a consulting firm with specific expertise in detailed fuel supply and price analysis or developed by the utility if it has expert knowledge and expertise with the fuel under consideration. Each forecast shall consider at least the following factors as applicable to each fuel under consideration:**
    - A. **Present reserves, discovery rates and usage rates of the fuel and forecast of future trends of these factors;**
    - B. **Profitability and financial condition of producers;**
    - C. **Potential effect of environmental factors, competition, and government regulation on producers, including the potential for changes in severance rates;**
    - D. **Capacity, profitability and expansion potential and present and potential fuel transportation options;**
    - E. **Potential effects of government regulations, competition and environmental legislation on fuel transporters;**
    - F. **In the case of uranium fuel, potential effects of competition and government regulations on future costs of enrichment services and cleanup of production facilities; and**

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

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

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

This section is broken down into three sections: natural gas price forecast, nuclear fuel price forecast, distillate fuel oil price forecast, and coal price forecast.

NATURAL GAS PRICE FORECAST

Overview

CRA International's MRN-NEEM model relies upon external forecasts for base case natural gas prices. From 2007 through 2012, CRA uses monthly NYMEX spot futures prices at Henry Hub, given that each futures month was traded at a sufficient volume. From 2015 through 2030, MRN-NEEM takes projected annual Henry Hub natural gas prices as provided in the 2007 Energy Information Administration's (EIA) Annual Energy Outlook (AEO). In the intervening years from 2013 through 2014, the model sets natural gas prices by linearly interpolating between the NYMEX futures and the 2007 AEO forecasts. These prices are (1) seasonally adjusted based upon historical monthly prices, governed by the month-to-season mapping in Table 65, and (2) regionally adjusted based upon historical basis differentials from Henry Hub to 25 different U.S. plant gates. 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.

Table 65: Assignment of Months to Seasons in the MRN-NEEM Model.

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

Figure 23 below depicts the base case wellhead natural gas prices underlying the delivered seasonal prices of the MRN-NEEM model. Despite being used in the probability elicitation process, note that the prices in this graph do not wholly represent the natural gas prices projected to prevail in Eastern Missouri during the planning horizon. In the detailed responses to subsections A-F to follow, much of the discussion is derived directly from 2007 AEO documentation, as AEO forecasts form the backbone of MRN-NEEM natural gas prices through much of the IRP horizon. Although this information supports the base case forecasts in Figure 23, it does not completely embody AmerenUE's subjective assessment of natural gas price uncertainty. The inclusion of base case and high natural gas price trajectories in the probability tree is explained more fully in the response to section 4 CSR 240-22.040 (8) (A) 3.

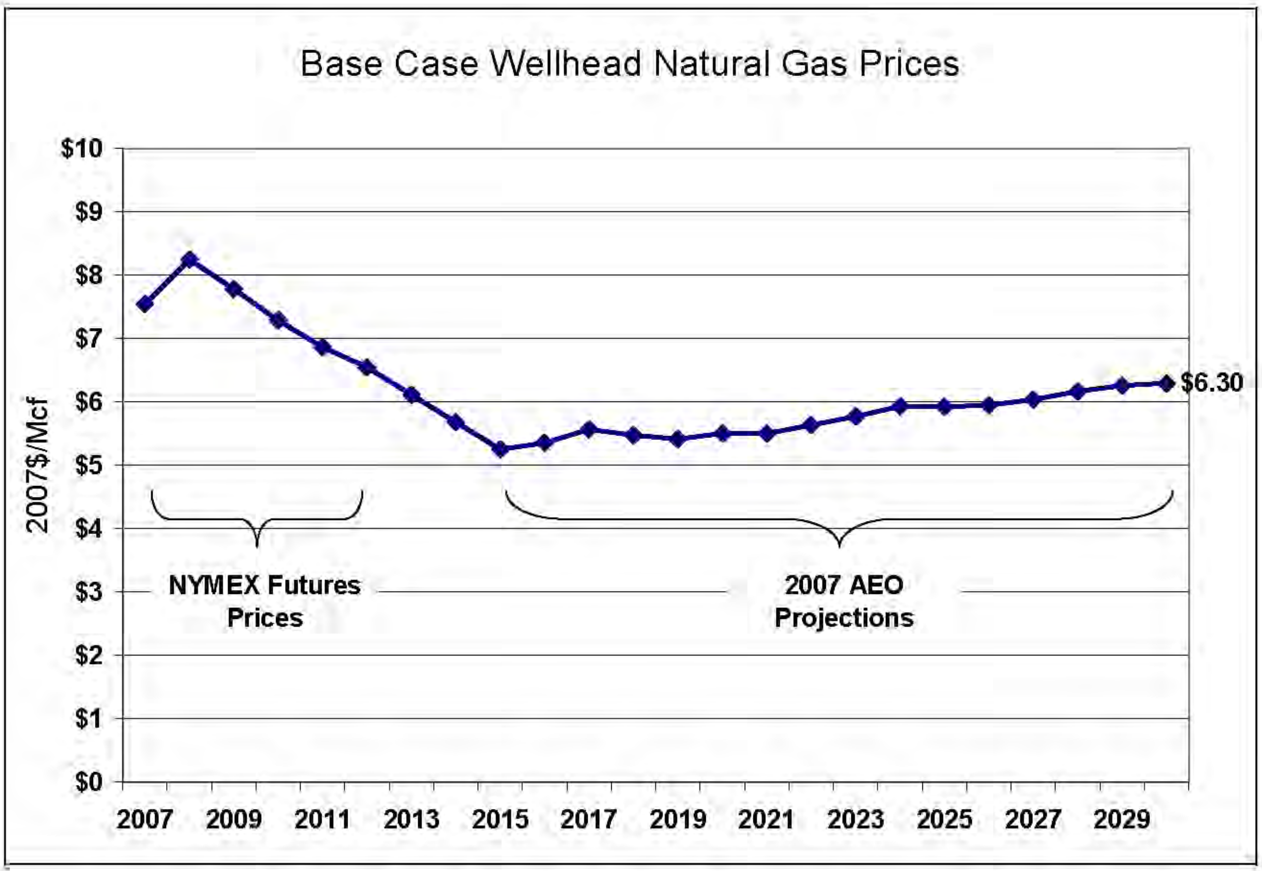

Figure 23: MRN-NEEM Base Case Wellhead Natural Gas Prices at Henry Hub.

1. A.

Present Reserves

One of the key assumptions underlying EIA projections of natural gas supply and price levels concerns estimates of domestic technically recoverable[1] gas resources. As of January 1, 2005, the EIA reported that the technically recoverable natural gas resources,

[1] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

both proved[2] and unproved, totaled 1,341 trillion cubic feet (Tcf).[3] This level reflects the fact that a large proportion of the onshore natural gas resource base retrievable by conventional[4] methods has already been discovered. Indeed, the rising natural gas prices in the post-2015 timeframe in Figure 23 signal an anticipated decline in U.S. technically recoverable resources from the aforementioned levels. As mature conventional basins are depleted and new onshore conventional basins prove smaller and deeper, more and more of domestic demand for natural gas will have to be met through more costly non-conventional recovery techniques.[5] Outside of the lower 48 states, considerable natural gas resources remain in the offshore Gulf of Mexico, especially in the deep waters exceeding 200 meters in depth. Production patterns from currently producing fields and industry announced discoveries largely determine short-term gas production, while the discovery of and production from new natural gas reserves in the Gulf are assumed to follow historical trends.[6] In addition, the Alaska natural gas pipeline is expected to begin transporting natural gas to the lower 48 states in 2018, such that, by 2030, around 2.2 Tcf of U.S. natural gas supply traces back to Alaska.[7]

---

[2] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3] EIA Annual Energy Outlook 2007, p. 91, Table 17 (192.5 Tcf proved, 1,148.5 Tcf unproved). Resource assumptions are based upon estimates extrapolated by the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior, with supplemental adjustments to the USGS non-conventional gas resources established by Advanced Resources International.

[4] Non-conventional methods include gas recovery from low permeability formations of sandstone and shale, and coalbeds.

[5] In fact, the EIA AEO 2007 reference case projects that unconventional production in the contiguous United States will account for 50% of domestic U.S. natural gas production by 2030. EIA Annual Energy Outlook 2007, p. 93.

[6] EIA Assumptions to the Annual Energy Outlook 2007, p. 94. Production is assumed to ramp up to a peak level in 2 to 4 years depending on the size of the field, remain at the peak level until the ratio of cumulative production to initial resource reaches 30 percent, and then decline at an exponential rate of 20 to 30 percent.

[7] EIA Annual Energy Outlook, p. 93.

Imports of natural gas are expected to meet an increasing share of domestic consumption, with most of this growth due to increased liquefied natural gas (LNG) consumption.[8] Current high natural gas prices are expected to stimulate the construction of new LNG terminal capacity to accommodate this surge in LNG imports to approximately 6.5 Tcf in 2030. EIA forecasts foresee no hard ceiling on the potential for growth in LNG supply, as, unlike the situation in the United States and Canada, the rest of the world has not significantly exploited its natural gas resource base. However, the U.S. LNG market is expected to be tight through 2012 because of supply constraints at a number of liquefaction facilities, delays in the completion of new liquefaction projects, and rapid growth in global LNG demand.[9] In contrast, net imports from Canada are projected to decline largely as the result of (1) reductions in Canada's non-Arctic, conventional natural gas production in Alberta and (2) increases in Canada's domestic consumption. These shortfalls are only partially offset by the completion of the MacKenzie Delta natural gas pipeline, assumed to occur in 2012.[10]

Discovery Rates

In general, the exploration and production (E&P) of natural gas becomes more profitable when prices increase and development costs decline. In MRN-NEEM, elasticities of production determine supply responses to changes in fuel prices, and higher or lower prices incentivize or discourage E&P activities according to these elasticity parameters. Development costs are a direct function of the rate of improvement in natural gas extraction technology. Not only can advances in technology reduce production costs from existing reserves, but they can also expand the economically recoverable resource base.[11] The AEO reference case assumes that technology will continue to penetrate at historically observed rates. Technology progress on conventional natural gas parameters in the reference case encompasses such things as finding rates,

[8] *Ibid*, p. 94.

[9] *Ibid*, p. 94.

[10] *Ibid*, p. 94.

[11] *Ibid*, p. 91.

drilling, lease equipment and operating costs, and success rates. The reference case also simulates the effects of technological progress on the costs and productivity of non-conventional natural gas development from coalbed methane, gas shales, and tight sands.[12] The supply prices undergirding this scale of technology maturation are assumed to be high enough to trigger the commercial deployment of both the Alaska and MacKenzie Delta pipelines in the AEO reference case.

Usage Rates

Natural gas price movements most formatively affect levels of natural gas usage because they provide a direct incentive to either ramp down or up consumption. In the electric sector particularly, the projected upswing in delivered natural gas prices precipitates the switch to new coal-fired generation from natural gas, leading to a decline in natural gas consumption.[13] This will almost completely offset projected growth in the residential, commercial, industrial, and transportation sectors, which are less sensitive to price assumptions due to lesser fuel substitutability and the slower turnover rates of the natural gas-fired stocks of equipment. For all these reasons, EIA forecasts a slight increase in domestic natural gas consumption from 2005 through 2030, but with levels staying relatively flat between 2020 and 2030.

1. B.

The profitability and financial condition of producers is a function of the costs of extraction and the prevailing market price for natural gas. Given a baseline natural gas price forecast and any policy prescriptions for CO_2 abatement or otherwise, the MRN-NEEM model dynamically models net gains or losses to various production sectors, including oil and gas extraction and gas distribution. For trade-exposed sectors facing international competitors, MRN-NEEM also simulates the leakage of economic activities outside of the United States. It should be noted that the model assumes perfectly functional and competitive commodities markets, and that it plots a least-cost

[12] EIA Assumptions to the Annual Energy Outlook 2007, pp. 100-101.

[13] EIA Annual Energy Outlook, p. 89.

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.

1. C.

Environmental Factors

The MRN-NEEM model accounts for all environmental regulations currently projected through the planning horizon. This includes Federal caps on SO_2, NO_X, and Hg emissions, as documented in section 4 CSR 240-22.040 (2) (B) 4, and any binding RPS requirements throughout the country. Since natural gas emits significant amounts of CO_2 emissions, AmerenUE duly considered the potential for mandatory abatement. The CO_2 policy branches in the probability tree encapsulate what AmerenUE 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_2 policies concern natural gas production sectors.

Competition

The consumption of natural gas in the United States spans across various 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 how oil, gas, and coal are 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.[14] 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.[15] As another example, rising delivered natural gas prices from 2015 onward can reliably expect to cause a turnover of natural gas generators in favor of new coal (in a

[14] EIA Annual Energy Outlook, p. 93.

[15] *Ibid*, p. 93.

case with no limits on carbon emissions). The manifold ripple effects in these illustrative examples demonstrate how interrelated natural gas, coal, and fuel oil prices are. Therefore, AmerenUE's integrated resource plan was founded upon projections of key IRP variables from an energy and environment model (MRN-NEEM) capable of properly accounting for macroeconomic feedback effects between electricity demand, electricity prices, and natural gas, coal, and fuel oil prices and consumption levels.

Government Regulation

The base case forecasts for domestic natural gas prices presuppose that royalty relief for natural gas exploration in the offshore Gulf of Mexico conforms to the guidelines stipulated by Section 345 of the Energy Policy Act of 2005 and the Mineral Management Service's (MMS) final rule on the "Oil and Gas Sulphur Operations in the Outer Continental Shelf – Relief or Reduction in Royalty Rates – Deep Gas Provisions."[16] These guidelines shape the E&P costs of the up to 3.1 Tcf EIA projects to be annually produced from the Gulf, and as such, are important in establishing base case natural gas prices. Section 345 furnishes royalty relief for oil and gas production in water depths greater than 400 meters for any oil or gas lease sale occurring within 5 years after the enactment, provided minimum volumes of production are satisfied.[17] The MMS final rule grants full relief from royalty payments for leases issued prior to January 1, 2001 with wells drilled to at least 15,000 feet in the shallow waters of the Gulf (again subject to certain minimum volume requirements), relief for up to 5 billion cubic feet of natural gas for unsuccessful wells drilled to at least 18,000 feet, and full suspension for volumes of at least 35 billion cubic feet for ultra-deep wells.[18] Although there is considerable uncertainty surrounding the treatment of royalty payments further down the line, the base case natural gas prices assumed a continuation of the present form of law.

[16] EIA Assumptions to the Annual Energy Outlook 2007, p. 100.

[17] *Ibid,* p. 100.

[18] *Ibid,* p. 100.

1. D.

As previously described, sustained high natural gas prices will incite expanded investment in transportation infrastructure. First, even in the base case, these prices are high enough to support the construction of both the Alaska and the MacKenzie Delta natural gas pipelines into the continental United States. Second, these prices will stimulate the construction of new LNG import capacity within the United States, allowing for a surge in LNG imports. Lastly, the growing demand for natural gas will necessarily require general upgrades to the domestic pipeline distribution network. Both EIA forecasts and MRN-NEEM modeling assume that enough transmission and distribution (T&D) capacity will be built to accommodate projected growth in natural gas consumption. In so maintaining a constant equilibrium between supply and demand, MRN-NEEM fixes the regional basis differentials that represent the transportation costs from wellhead to end-use location.

Increased reliance on LNG imports is contingent upon several technological and political factors. First, despite there being more than adequate world reserves, the areas holding the most readily accessible stores (Russia, Qatar, South America, Africa) are fraught with political volatility. Furthermore, the liquefaction of natural gas in these host countries is an extremely complex and expensive process, and many current projects are stalling due to engineering constraints and unexpected cost overruns. To satisfy the burgeoning global demand in the short- and long-term, there will need to be an increase in liquefaction capacity beyond those projects presently in queue, which will require both advancements in liquefaction technology and broader political adoption of liquefaction projects in developing countries. Even supposing that this occurs with certainty, the United States could face volatility in natural gas prices if new load pockets for LNG emerge. Europe's collective willingness to rely on Russian natural gas rather than LNG and the future energy profile of China and other rapidly developing nations are both relevant concerns in this regard.[19] Secondly, the costs of transporting LNG from these

[19] For instance, if China and the developing world increasingly open up to global natural gas supplies in place of continued reliance on coal or a switch to nuclear, then natural gas prices can expect to rise in the United States.

developing countries to load centers (United States, Europe) are another expensive component of the supply chain, and, as such, there will need to be technological progress and consolidation in supertanker shipping. Third, the siting of LNG terminals in populated U.S. demand centers is likely to meet political resistance, in the form of NIMBY, or not-in-my-backyard, protest.[20] Finally, the market structure governing LNG contracts has yet to be standardized, particularly the choice between spot and long-term contracts.[21]

To reiterate, the base case natural gas price forecasts assume (and support) a significant increase in LNG import capacity in the United States. However, the considerable uncertainty enveloping the fate of LNG consumption in the United States described above was not ignored for capacity planning purposes. AmerenUE identified natural gas prices as one of the critical uncertainties in developing build plans, and, as such, formed a set of nodes in the probability tree to appropriately capture this uncertainty. This process is further explained in the response to section 4 CSR 240-22.040 (8) (A) 3.

1. E.

As first laid out in the response to section 1.D, MRN-NEEM takes for granted any expansions in T&D infrastructure necessary to sustain projected increases in domestic natural gas demand. Driven by the assumption that the costs of adding new facilities are roughly equivalent to the foregone depreciation expenses at existing facilities, end-use T&D margins stay relatively flat through the planning horizon.[22] Nevertheless, public opposition to invasive T&D construction activities in their backyard has the potential to

[20] There is also concern about the cost-effectiveness of regasification plants at current output levels, but this constraint is not expected to be as pressing as those on the liquefaction side of the production chain.

[21] Even if natural gas prices in the United States are higher than in the rest of the world, the current propensity for LNG producers to demand netbacks over and above the costs of every component of the supply chain (exploration and production, shipment to liquefaction facilities, liquefaction, supertanker shipping to demand centers, regasification) might lure potential supply away from the United States to other nations offering greater returns.

[22] EIA Annual Energy Outlook 2007, p. 92.

stymie natural gas fuel transporters' least-cost operations, which would obviously exert upward pressure on delivered natural gas prices. In the foreseeable future, the industrial and electricity sectors will continue to enjoy the lowest end-use natural gas prices, because they (1) receive most of their gas directly from interstate pipelines, thus avoiding local distribution charges, and (2) summer-peaking electricity generators can limit T&D costs by using interruptible transmission services in the summer, when there is spare pipeline capacity. However, if power generators acquire a larger share of the natural gas consumption market (in response to some form of carbon policy, for instance), then this spare summer pipeline capacity could evaporate, and generators will be forced to rely more upon higher-cost firm transmission service from natural gas transporters.[23] Depending upon its coverage of the economy, federal CO_2 abatement policies could also penetrate directly into energy-intensive transport industries, like high-GWP (global warming potential) methane operations in pipeline transportation. MRN-NEEM properly simulates the increased costs that natural gas transporters would incur under such a regime. Further, the set of MRN-NEEM modeling scenarios in the probability tree fully spans the range of CO_2 policy uncertainty surrounding the natural gas transportation and all other energy-intensive sectors.

1. F.

This section is not applicable to natural gas price forecasts.

1. G.

AmerenUE expects no restrictions on the use of natural gas in electricity generation within the IRP time period. More probable restrictions on electricity generation from other fuel types could influence the pattern of natural gas consumption, though. For instance, the Mandates CO_2 policy case envisions a prohibition on new coal-fired plants after 2015. When the existing coal fleet retires, natural gas will move up in the merit order and increasingly serve base load demand.

[23] *Ibid*, p. 92.

2.

AmerenUE judges the NYMEX natural gas futures exchange and 2007 Annual Energy Outlook to be the best forecasts available for base case natural gas prices. CRA International's MRN-NEEM model has been extensively peer-reviewed by such reputable organizations as the International Panel on Climate Change (IPCC) and the Stanford Energy Modeling Forum, and, as such, represents 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.

3.

An integral component of a risk analysis of alternative resource plans is the assignment of subjective probabilities to each of the critical uncertainties. That is, the following uncertainties encompassed in the probability tree need to be stated as a probability distribution function (pdf):

1. Greenhouse gas (GHG) policy outcomes, especially in terms of CO_2 price levels;
2. Natural gas prices;
3. Load growth paths, especially in terms of breakthroughs in energy efficiency and distributed generation.

Having assigned a probability to each of the three forks in a tree branch, the likelihood of an integrated scenario (*i.e.*, of the endpoint in a tree branch) is simply the product of the probabilities of each fork. The elicitation process on natural gas prices conformed to the tenets of decision analysis laid out in the response to section 4 CSR 240-22.030 (7).

CRA interviewed three AmerenUE experts in the elicitation of natural gas price paths: (1) Scott Glaeser, Vice President, Gas Supply and System Control; (2) Jim Massmann, Manager, Gas Supply; and (3) Shawn Schukar, Vice President, Ameren Energy. First, CRA moderated a group discussion of the fundamentals driving gas prices, during which the experts hashed out a matrix of the landscape-shaping drivers that could swing natural gas prices. These drivers constituted both supply- and demand-side phenomena, and, due to the projected widening scope of LNG, were both global and domestic in nature. Once a comprehensive list had been developed, CRA isolated the experts' thought processes around each driver individually. This strategy, coined "modeling" in decision analysis dogma, facilitated a clear, focused evaluation of less-complex determinants of natural gas prices. Taken together, these evaluations collectively indicated the experts' true beliefs on what directions natural gas prices could take. AmerenUE and CRA jointly established the following list of critical factors influencing natural gas prices:

- Long-term growth of worldwide LNG liquefaction capacity;
- Political support of natural gas production in the offshore and the Rockies, and the fate of the Alaska and MacKenzie Delta pipelines;
- Estimates of the conventional and unconventional U.S./Canadian natural gas resource base;
- Steel prices and construction costs;
- Technological improvement in drilling and reservoir stimulation;
- Ability to build new coal and nuclear power plants;
- Demand for natural gas in China and the rest of the developing world;
- CO_2 policy outside of the United States;
- Europe's willingness to rely on Russian natural gas imports;
- Status and use of natural gas in oil sands projects;
- Economic growth in the United States and abroad (especially in China);
- World oil prices; and
- Breakthroughs in renewable technologies, energy efficiency standards, and demand side management (DSM) programs.

To then gauge in what "directions" these factors would push natural gas prices, AmerenUE concentrated upon estimating a long-run equilibrium price in the absence of any carbon abatement policy; that is, in the BAU scenario.[24] In particular, the price elicited was the 2030 average U.S. wellhead price per million cubic feet (Mcf) of natural gas, stated in real (2007) dollars. The envisioned trajectory through 2030 would simply be an interpolation between current prices and the elicited price. Before developing an actual probability distribution function of this variable, CRA and AmerenUE jointly devised, for each of the critical drivers, sets of circumstances that would result in low, median, and high price trajectories, respectively. The "low" set included all 2030 average wellhead prices less than roughly [redacted]Mcf, the "median" set ranged from [redacted]Mcf to [redacted]Mcf, and the "high" set encompassed prices ranging from around [redacted]Mcf to [redacted]Mcf.[25] Having clarified the key drivers affecting natural gas prices and having stratified possible trajectories for those prices, CRA and AmerenUE created the matrix reproduced in Figure 24. AmerenUE formulated a story for each driver consistent with each set of prices, and then stepped back to assess what story (or stories) was most realistic. The shading in each row of the matrix in Figure 24 reflects the experts' consensus on the most likely outcomes for each driver. Figure 25 depicts the experts' consensus views on gas price outcomes alongside a series of other projections compiled in the 2007 EIA AEO.[26]

[24] Integrated MRN-NEEM modeling of the scenarios spanning the range of probability in the IRP tree would properly simulate how various CO_2 policies would impact natural gas prices.

[25] In 2005 dollars, the "low" set is equivalent to all prices less than $5/Mcf, the "median" set to prices between $5.50/Mcf and $7.50/Mcf, and the "high" set to prices from $8/Mcf to $12/Mcf (assuming 2.5% annual inflation).

[26] EIA Annual Energy Outlook 2007, Table 22, pp. 111-112.

Matrix of Drivers Developed During Gas Price Elicitation

(shading across a row reflects experts' consensus on most likely outcomes of each driver)

Driver	Gas prices lower	←→	Gas prices higher
LNG *(Policy - supply)*	Developing country govts support expansion of liquefaction projects	Increase in liquefaction capacity worldwide beyond current projects (2012)	No increase in liquefaction capacity worldwide after 2012
Access to US/Canadian Natural Gas Resources *(Policy - supply)*	Both Alaska and Mackenzie Delta pipelines get built. Better access to federal lands in the offshore and Rockies and Canada/Alaska through less opposition/lower taxes.	Current limits on drilling in Gulf/ Rockies, either Alaska pipeline or Mackenzie Delta pipeline gets built	More limited access to new supply projects; no Alaska or Mackenzie Delta pipeline; high severance taxes and royalties
Ability to Build New Coal/ Nuclear Power Plants *(Policy - demand)*	Limits on ability to build new coal and nuclear power plants not large enough to result in uneconomical gas builds	Some limits on ability to build new coal and nuclear power plants w/o CO_2 pricing	Greatly restricted ability to build new coal and nuclear power plants w/o CO_2 pricing
China/ Developing World Demand for Natural Gas *(Policy - demand)*	China/Developing World opts for coal and nuclear	China/Developing World increase gas imports (energy share holds constant)	China/Developing World opens up to global natural gas supplies
CO_2 Policy Outside US *(Policy - demand)*	Europe/Japan stop CO_2 policy	Europe/Japan have moderate CO_2 policy (continuation of Kyoto commitment forever)	Europe/Japan have stringent CO_2 policy (stringent enough that EU would have no coal generation)
Europe's Willingness to Rely on Russia *(Policy - demand)*	Europe relies heavily on Russian imports rather than LNG (with result of more LNG available to US)	Europe continues to rely on LNG, and less reliant on Russia for supply	Europe unwilling to rely on Russia for supply or Russia unwilling to supply to Europe (i.e. less LNG available to US)
US/Canadian Natural Gas Resource Base *(Supply - physical)*	Coal bed methane and tight gas resources greater than USGS estimates of economic resource	Declining conventional resource base; CBM and tight gas at USGS levels	CBM and tight gas resource less than USGS estimates
Steel Prices & Construction Costs *(Supply - cost)*	Steel prices fall all the way back to historical average levels	Slower growth in China & increased investment in steelmaking capacity allows steel prices to fall from current highs, but remain higher than historical averages	Continued high steel and other material costs (one vote here for pale yellow)
Technological Improvement in Drilling and Reservoir Stimulation *(Supply - cost)*	Increased rate of technological improvement above historical levels	Technological improvement rates at roughly historical levels	Technology improvement rates decline from historical levels
Oil Sands *(Demand)*		Oil sands projects move forward using petroleum coke to produce steam (not natural gas)	Oil sands projects move forward, but limited to using natural gas to generate steam
Economic Growth *(Demand)*	Low growth relative to historical levels	Normal growth in US, moderating growth in China	Normal growth in US, continued high growth in China
World Oil Price *(Demand)*	Low oil prices	Prices at roughly current levels ($60/bbl)	High oil prices
Renewables/ Energy Efficiency/ Demand Side Management *(Demand)*	Technological breakthroughs in En Efficiency and distributed generation	Moderate increases in renewables/energy efficiency/demand side management	Few breakthroughs in green technologies (renewables/distributed generation/energy efficiency)

Figure 24: Matrix of Drivers Developed During Natural Gas Price Elicitation.

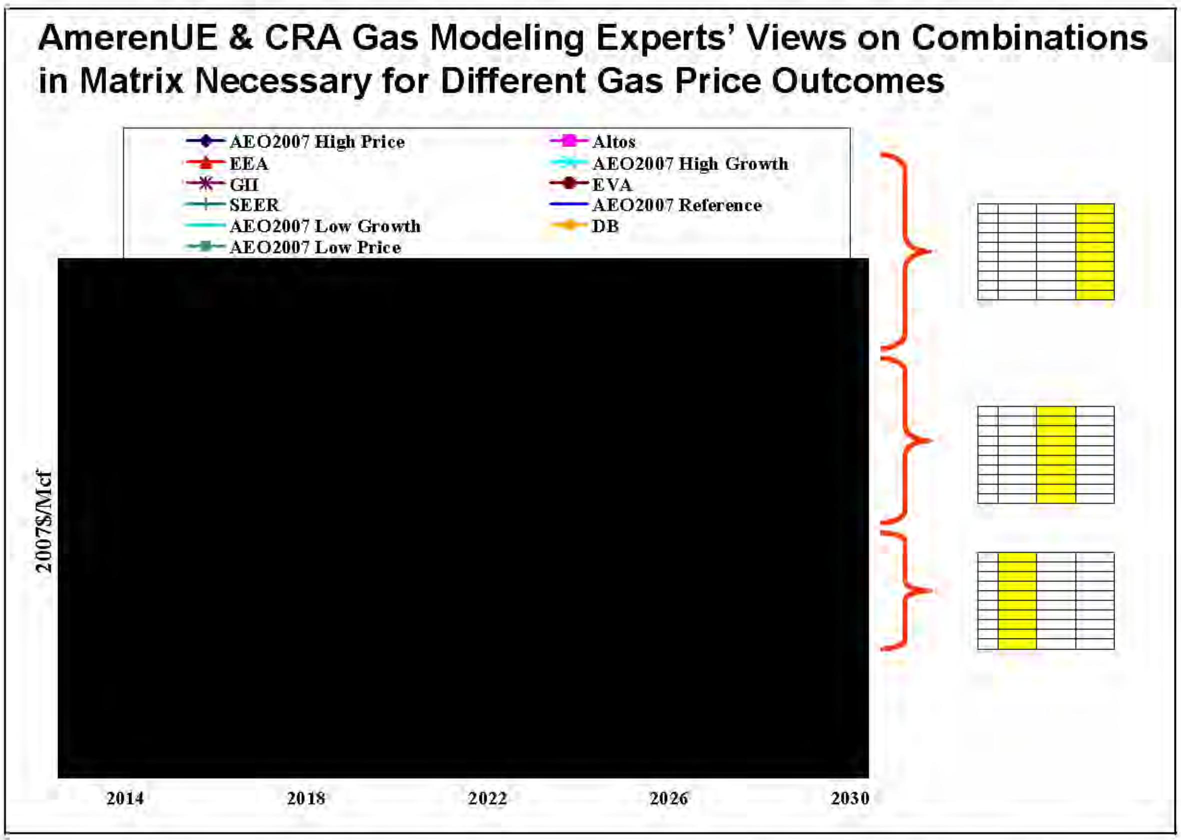

Figure 25: AmerenUE Experts' Consensus Natural Gas Price Views Alongside EIA-Compiled Projections.

After calibrating the discussion around the matrix in Figure 24, each of the AmerenUE experts independently developed a probability distribution function for the 2030 average U.S. wellhead price of natural gas. First, the experts established a lower bound below which supply would dry up and an upper bound beyond which demand would erode. For the group, this range spanned from [redacted]Mcf through [redacted]Mcf to [redacted]Mcf. Within these bounds, CRA then systematically elicited probabilities for natural gas prices at $0.50 increments, not necessarily in consecutive fashion, from each expert. This process was very interactive in nature, and AmerenUE experts occasionally revisited their assessments if presented with inconsistencies in the shape of the curve. The general curvature of the continuous probability distribution functions varied slightly between the experts, as did the resulting median value, ranging from [redacted] to [redacted]Mcf. The best single two-branch discretization to fit each of the three pdfs was a "base" natural gas price of [redacted]Mcf in 2030, consistent with the path in Figure , and a "high" gas price of [redacted]Mcf. Figure 26 presents the assignment of subjective probabilities for this two-branch discrete pdf. As demonstrated by the previously developed continuous pdfs, the experts agreed on the probable range of natural gas prices, but assigned somewhat different relative probabilities to the higher and lower parts of the range. Nevertheless, given the balance in their views, the experts eventually decided that the 50% - 50% split was a reasonable final assignment.

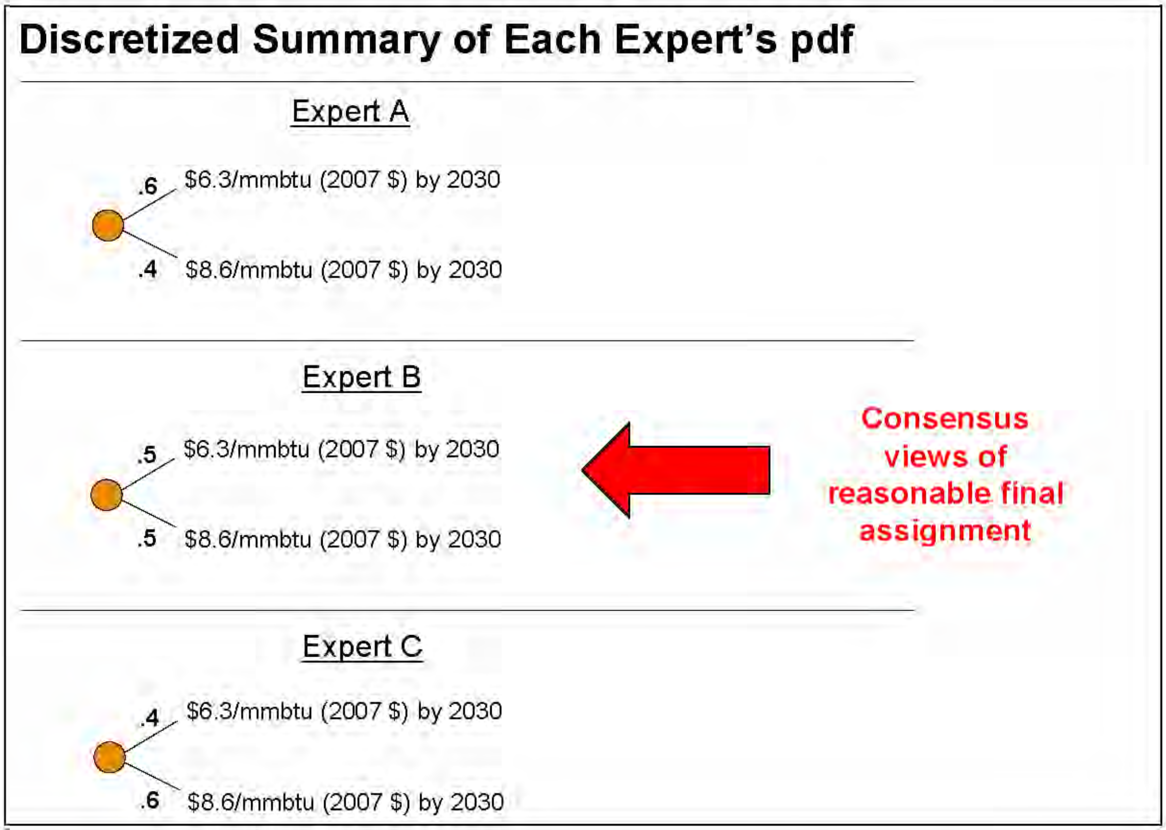

Figure 26: Each Expert's Discretized Probability Distribution Function for Natural Gas Prices.

Figure 27 presents the final natural gas price branches in the probability tree along with the consensus subjective probabilities of Figure 26. Note that the high gas price case uses the same NYMEX futures prices as in the base gas price case through 2012, and then linearly interpolates between that price level and the [redacted]Mcf price level in 2030 for the remaining IRP years. These two paths, in AmerenUE's estimation, encapsulate the full range of reasonable uncertainty in natural gas prices within the planning horizon.[27]

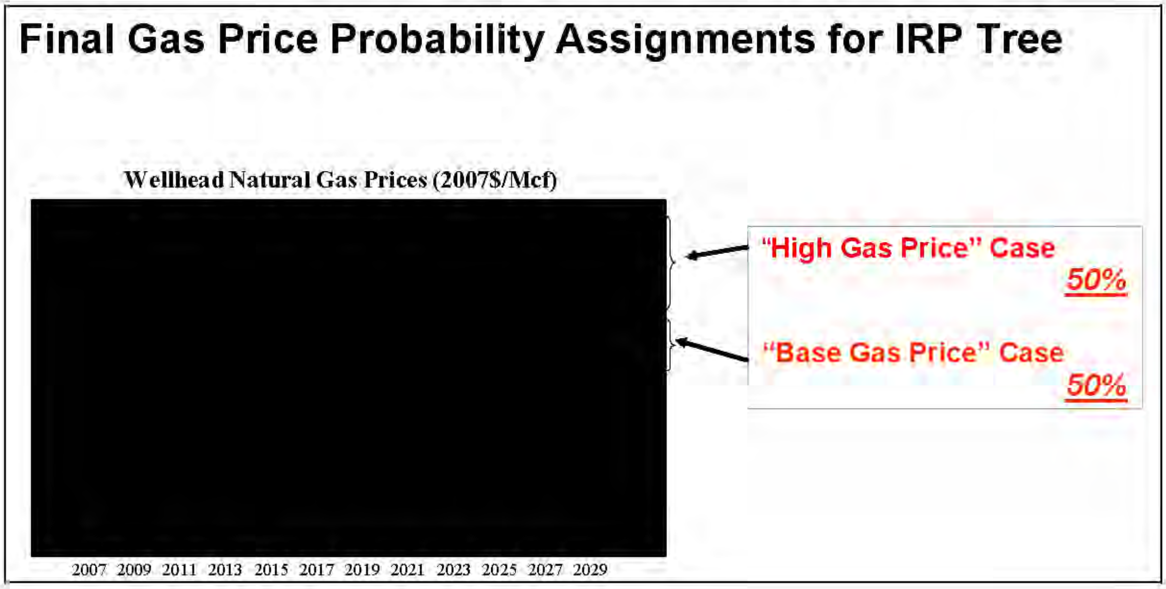

Figure 27: Final Natural Gas Price Probability Assignments for IRP Tree.

These natural gas price forecasts, again, represent average wellhead natural gas prices. However, the prices used in the modeling and risk analysis of alternative resource plans need to reflect the costs of delivery into AmerenUE's service territory per unit energy. Figure 28 converts the price paths above in Figure 27 into IRP input units (nominal $/MMBtu), and, consistent with how the MRN-NEEM model simulates natural gas prices, also demonstrates the seasonal variations typical of the annual cycles in natural gas demand. Due to higher demand for natural gas for residential and commercial heating, higher natural gas prices characterize the winter months.

[27] See Table D - 1 in Appendix H for a data table of both of the natural gas price scenarios included in the probability tree.

Figure 28: Delivered Natural Gas Prices into AmerenUE, in IRP Input Units (Nominal $/MMBtu).

Figure 29 below presents delivered natural gas prices in Eastern Missouri from each of the nine scenarios in the probability tree. Taking the base and high gas prices in Figure 27 and Figure 28 as inputs, the MRN-NEEM model properly simulates the macroeconomic feedback effects throughout the 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.[28]

---

[28] See Table B - 6 in Appendix F for a data table of MRN-NEEM delivered natural gas prices in Eastern Missouri.

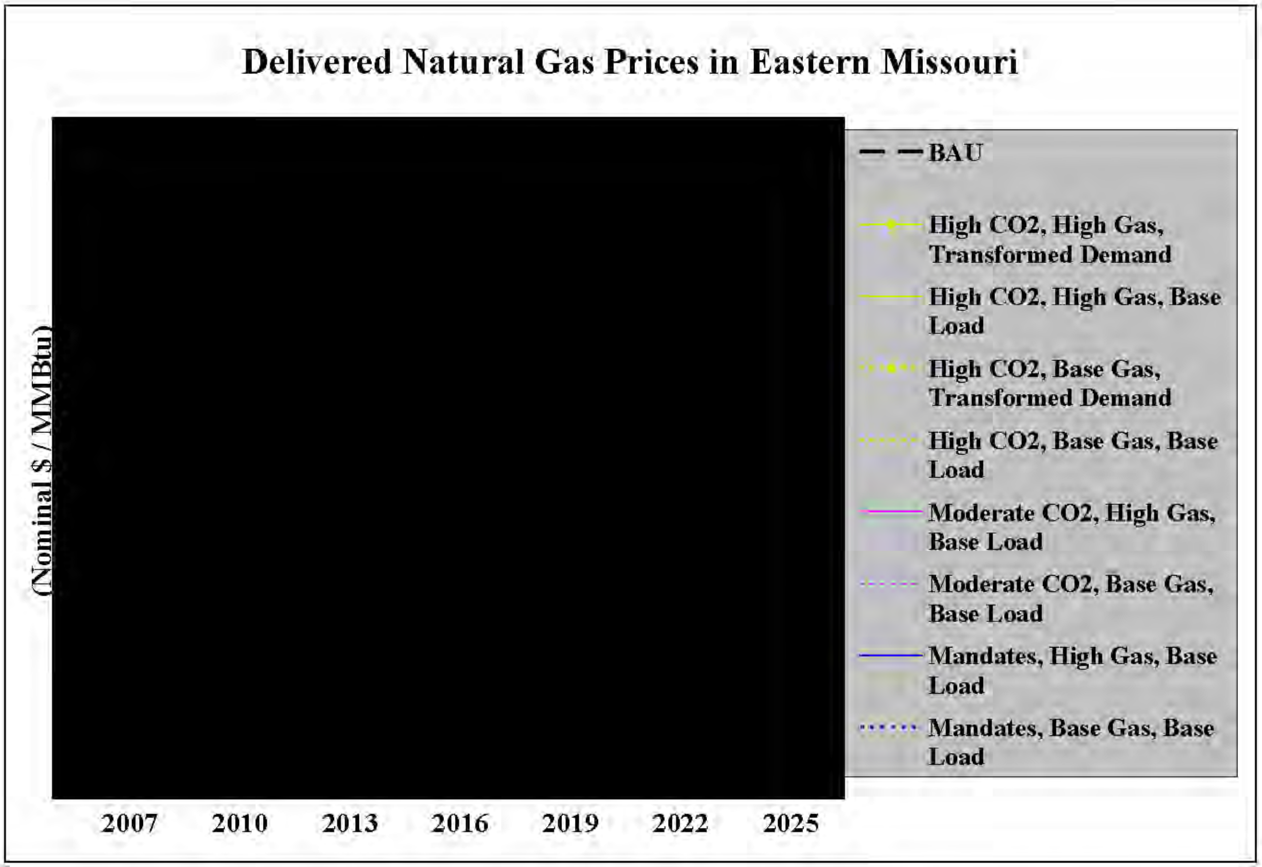

Figure 29: MRN-NEEM Delivered Natural Gas Prices in Eastern Missouri (Nominal $/MMBtu).

NUCLEAR FUEL PRICE FORECAST

Overview

The nuclear fuel industry transitioned from a twenty year inventory drawdown regime in 2003 to the current production expansion regime. During such prior regime, prices were low, supply plentiful, producers consolidated, workers exited the production sector, capital spending on current plants and new plants was low, small exploration budgets were the norm, and production was much less than consumption. In 2007, prices are high enough to encourage new production but it will take many years for new supply to meet demand for existing world-wide nuclear reactors at the same time new nuclear reactors are being planned. 1) How quickly new nuclear fuel production comes online world-wide and 2) how many new reactors are built world-wide and when, are the two greatest uncertainties.

Cost Forecast

The 2007-2026 nuclear fuel cost forecast (Appendix I) was done with the following assumptions:

1. used the current Surfn-nuclear accounting and cost forecasting model as used by Callaway 1.
2. used the current fuel design and energy requirements as Callaway 1; except that for uranium, conversion, and enrichment cost, used a 17% reduction to due improved fuel efficiency.
3. used current inventories and in-reactor fuel as Callaway 1 but did not use future supply contracts.
4. used the nuclear fuel consulting company UXC price forecast for uranium, conversion, and enrichment. Appendix J contains the latest quarterly reports for these costs components from UXC. This is UXC's proprietary information. UXC uses scenario analysis with assumptions for a low case, base case, and high case price forecast for uranium, conversion, and enrichment.
5. fabrication prices were assumed to be the current Westinghouse contract with normal contract escalation.
6. DOE spent fuel fee remains at current level.
7. No reprocessing of spent fuel.

Figure 30 below presents the total nuclear fuel costs from UxC's Base Commodity Spot Price[29] scenario, representing the median UxC forecast, within the planning horizon. These costs include direct, indirect, and miscellaneous expenses related to the uranium, conversion, enrichment, and fabrication components, as well as any spent fuel and decontamination and decommissioning charges.[30]

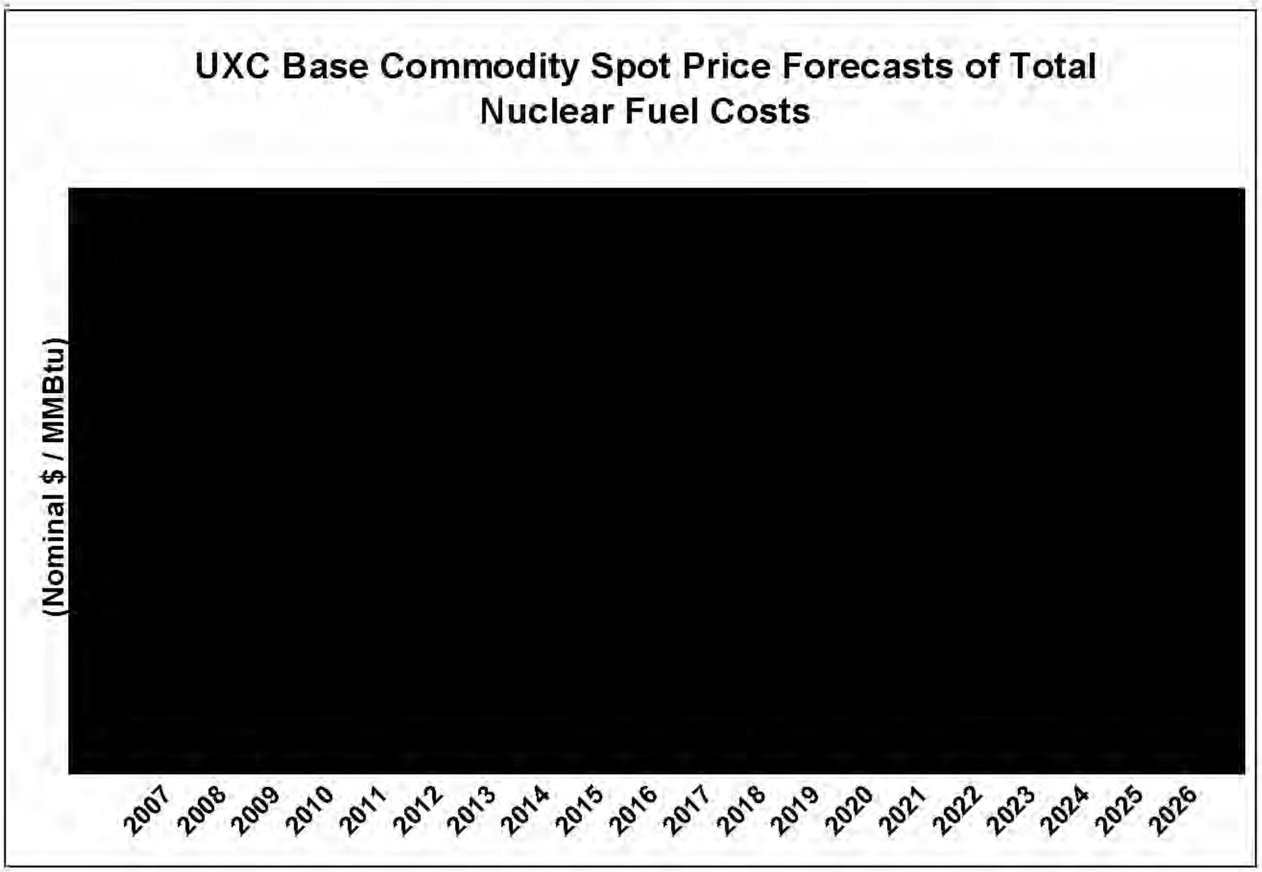

Figure 30: UxC Base Commodity Spot Price Scenario Forecasts of Total Nuclear Fuel Costs (Nominal $/MMBtu).

[29] The Ux Consulting Company, LLC (UxC), an affiliate of The Uranium Exchange Company, is an industry leader with recognized consulting and information services capabilities in uranium, enrichment, and conversion market analysis.

[30] See Table D - 2 in Appendix H for a data table of nuclear fuel costs.

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_3O_8) into UF_6, a fluorination step. Then the UF_6 is enriched in the isotope U235 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 were 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, there can exist trade barriers from time to time that impede the commercial flow of products and services.

Uranium is the only product while 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 are DOE spent fuel charges.

Uranium

Uranium cost uncertainty dominates the entire nuclear fuel cost. Actual future prices are difficult to forecast even six months out. Three years out is a very long price forecast. While cost of production needs to be under $50/lb. U_3O_8 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. Personally observing UXC uranium price forecasts over twenty years, they have a tendency to undershoot price peaks and overshoot price valleys. Also, there has been some relatively new entrants to the uranium market, uranium metal funds and speculators. They 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.

It takes any where from 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 U3O8 from ore. So it is difficult to see how the post 2013 supply gap will be filled from the market place. For 2007 and 2008, world-wide production expansion is not linked to price since it takes time to get new production online.

I personally doubt the uranium spot market price in 2020-2030 will be more than a factor of two higher than the attached UXC forecasts.

<u>Conversion</u>

Conversion is always a very small percentage of nuclear fuel costs. The industry is in a short term supply vs. demand balance. I believe the industry needs another new conversion plant and believe Cameco is uniquely positioned to do that, possibly at their Blind River, Ontario facility. The entire industry is subject to a potential major supply disruption if one facility is closed due to acts of god or accidents. ConverDyn and Urenco are talking about adding a conversion plant at one of Urenco's European facilities.

<u>Enrichment</u>

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 is being built in 2008, and 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. That issue is currently under negotiation between the two governments. To the extent that restriction is lifted, then more enrichment can be made available to U.S. nuclear plants. Russia has predominately the most unsold enrichment capacity in the 2010-2020 time period. If Russian can get both trade restrictions lifted and new supply contracts, then it can invest in new centrifuge production.

<u>Fabrication</u>

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.

(A)

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

Nuclear fuel price forecasts are attached from consulting companies. Nuclear Fuel "cost" forecasts are from these "price" forecasts using the Surfn-Nuclear Cost forecasting model. "Price" is what pays for each of the nuclear fuel components which are uranium, conversion, enrichment, and fabrication. "Cost" is the quantities of actual prices paid, accrued AFUDC, into fuel assemblies and the amortization of such assemblies using an energy burned method, typically over three years once initial heat production in the reactor has occurred.

There is no alternative fuel.

1.

AmerenUE used both the price forecasts of the world class UXC, and Energy Resources International, Inc. and the knowledge and experience of its expert nuclear fuel staff.

1. A.

These factors are not applicable to nuclear fuel price forecasts. UXC forecasts world supply and demand and their underlying factors. World inventory levels are very subjective with excellent data lacking.

1. B.

In general, prices in all components are sufficient for profitability, so this issue is not a factor in the nuclear fuel industry at this leg of the price cycle (rising and high prices). The only producer with below investment grade bond ratings is USEC and their future plans are questionable and is not the predominate new supply source for the industry world-wide.

1. C.

These factors do not appear to be applicable to nuclear fuel industry. The only factors in these categories that apply are the removal of the current trade restriction against Russian nuclear fuel in to the U.S. and the licensing of any new facility of any kind in the world. Any government regulation takes time for any new facility with potential for delays. Uranium mining bans in Australia have recently eased somewhat with more final say with the provinces. Approval of new uranium mills in Saskatchewan, Canada is undergoing further time than before to get regulatory approvals. UXC takes into account these factors in evaluating new production sources and their timing.

1. D.

Transportation in general is not applicable from a cost standpoint for nuclear fuel. However, adequate and declining availability of shipping transport and availability of regulatory approved shipping containers is an issue to be analyzed, but does not impact overall economics.

1. E.

Not applicable. See A.1.D.

1. F.

DOE decontamination and decommissioning fees for U.S. DOE enrichment facilities are already paid by the utilities with no current discussion of extending the surcharge. Current U.S. government policy is more amendable to more domestic competition in the enrichment sector as evidenced with the start of the construction of the National Enrichment Facility but can still be viewed as favoring USEC with some barriers of entry for new additional entrants. Areva is now planning to build a new enrichment facility in the U.S.

1. G.

No known restrictions currently. Only restriction is the importation of certain nuclear fuel products into the U.S. but that trade case is many years old and viewed by most as in its final stages with the likelihood of trade restrictions to be either eased or eliminated.

2.

There are three nuclear fuel price consultants; UXC, Trade Tech, and ERI. ERI has for many years had base escalated forecast that do not model the inherent dynamic factors in each market. However, they are fairly accurate and are the only ones that forecast fabrication prices. UXC has more manpower and information than Trade Tech in the areas of uranium, conversion, and enrichment price forecasts. We tried to get a study done by Duke Power a few years ago which compared forecasts over a ten year period which showed the UXC low case as the best predictor. However, that was in an inventory draw down regime.

3.

Each attached quarterly UXC report list the critical assumptions for each of the low, base, and high cases and assigns a probability to each case. While these assumptions and probabilities change over time, they tend to change slowly and sometimes new long term issues emerge.

CRA's response to 3. Sensitivity analysis using the MRN-NEEM model revealed that key IRP variables were not sensitive to variations in nuclear fuel prices, nuclear capital costs, and nuclear penetration levels. Thus, AmerenUE decided to exclude all forms of nuclear policy uncertainty from the final scenario tree. Also, the MRN-NEEM model does not simulate a competitive nuclear fuel market, and, instead, in this context, assumes the exogenous set of annual fuel costs specified in Figure 30. That is not to say, however, that the range of uncertainty reflected in the probability tree is completely divorced from the fate of nuclear generation in the United States. Under any meaningful CO_2 regime, nuclear power will have a significant cost advantage against traditional coal- and natural gas-fired base-load generation technologies, since it generates virtually zero lifecycle CO_2 emissions. In turn, the stringent CO_2 abatement regimes embodied in the high and moderate CO_2 price branches will incentivize construction of new nuclear generators across the nation. MRN-NEEM captures this phenomenon, albeit while setting reasonable limits on the number of new nuclear generating facilities that can be built and not fully simulating the upward price pressure that heightened EUP demand could exert.

DISTILLATE FUEL OIL PRICE FORECAST

Overview:

CRA International's MRN-NEEM model relies upon external forecasts for distillate fuel oil (DFO or FO2) prices. CRA assumes FO2 oil prices are uniform over each state and thus forecasts one price for each fuel per state per period. Fuel oil prices are derived as a combination of the principal driver and a regional differential. The principal driver underlying this forecast is the projected price for light sweet crude oil at Cushing, Oklahoma, which is used to derive the basis forecast. In the near term through 2012, the basis forecast is derived from NYMEX futures prices for light sweet crude oil as of May 7, 2007. From 2013 through 2015, the forecast is an interpolation between the last available year of futures and the 2007 Annual Energy Outlook. From 2016 through 2030, CRA relies on the AEO2007 forecast. The CRA basis forecast is shown below in Figure 31.

Figure 31: CRA Crude Oil Basis Forecast Alongside Historical Prices (2005$/bbl).

The basis forecast is then used to derive FO2 prices in the Mid-Atlantic region, which includes the state of New York. This regional forecast is prepared in three steps. First, CRA uses a regression model calibrated on historical data to derive prices for FO2 at New York Harbor from the basis forecast of crude oil prices. Next, New York Harbor prices (both FO2 and FO6) are linked to the AEO Reference Case forecast of U.S. average prices of each type of fuel oil used by electric utilities. This linkage is also based on historical regression. Finally, CRA uses the AEO forecast to develop yearly regional multipliers linking national average prices and prices to the Mid-Atlantic census region. Seasonal patterns are reflected by the monthly variations of NYMEX futures in the near-term, and by historical monthly patterns in the long-term. Delivered DFO prices, in terms of energy input, in the Eastern Missouri region appear below in Figure 32.[31]

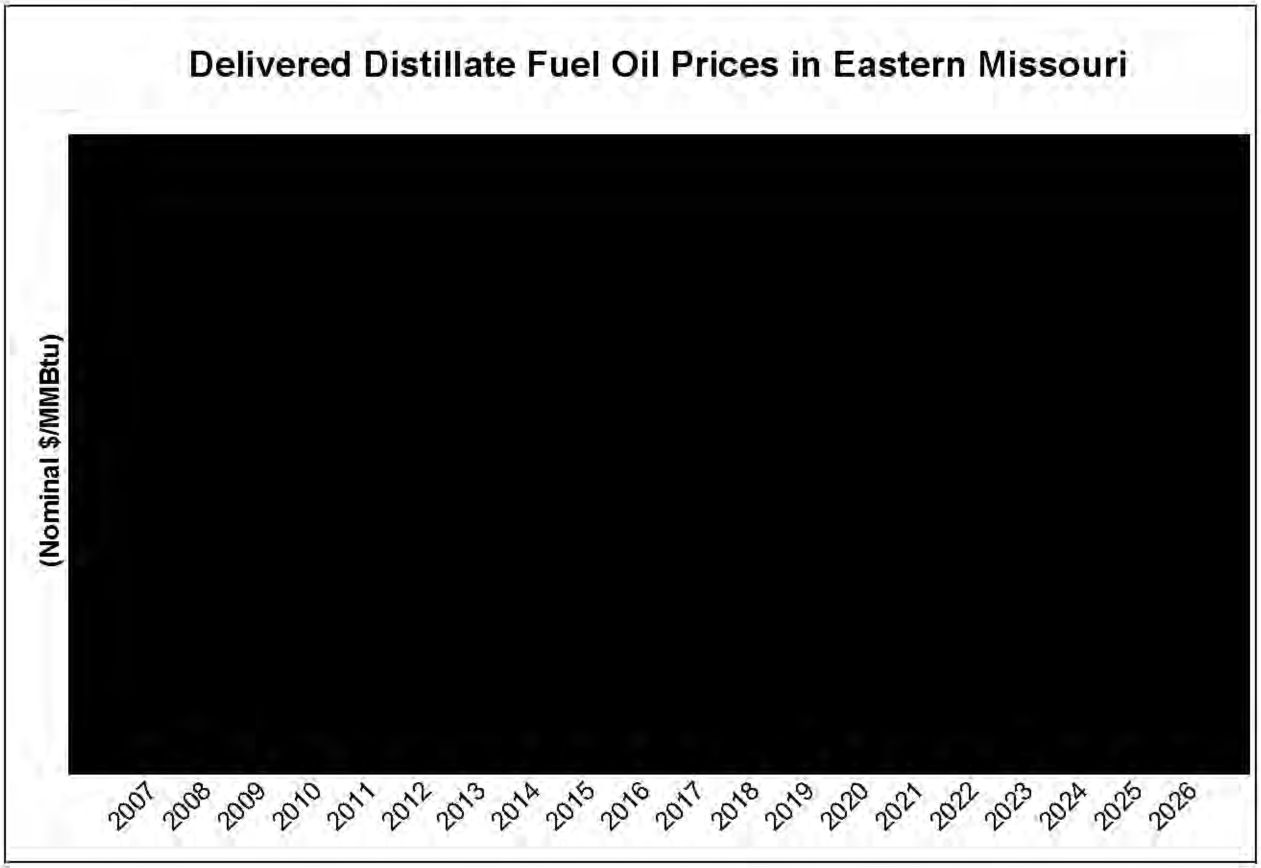

Figure32: Delivered Distillate Fuel Oil Prices in Eastern Missouri (Nominal $/MMBtu).

[31] See Table D - 3 in Appendix D for a data table of delivered DFO prices in Eastern Missouri.

1. A.

Present Reserves

As with natural gas, one of the key assumptions underlying EIA AEO 2007 projections of crude oil supply and price levels concerns estimates of domestic technically recoverable oil resources. As of January 1, 2005, the EIA reported that the technically recoverable crude oil resources, both proved and unproved, totaled 168 billion barrels (bbl).[32] Similar to the case with natural gas reserves, the domestic, onshore conventional oil resource base has been appreciably depleted, and new reservoir discoveries are likely to be smaller, more remote, and increasingly costly to exploit.[33] The rising crude oil prices in the post-2015 timeframe in Figure 32 are a reflection of this tight-supply reality. Sustained high oil prices, however, support the discovery and extraction of less accessible oil reserves via non-conventional methods such as enhanced oil recovery. The recent resource discoveries in the Bakken shale formation in Montana are directly reflective of such a trend, and lead to relatively constant projections of onshore crude oil production through 2030.[34] Outside of the lower 48 states, considerable resources remain in the offshore Gulf of Mexico, more so in the deep waters exceeding 200 meters in depth. Production patterns from currently producing fields and industry announced discoveries largely determine short-term gas production, while the discovery of and production from new oil reserves in the Gulf are assumed to follow historical trends.[35] In Alaska, with much of the retrievable oil resources shielded by the

[32] EIA Assumptions to the Annual Energy Outlook 2007, Table 50, p. 95 (22.59 bbl proved, 146.23 bbl unproved). Resource assumptions are based upon estimates extrapolated by the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior, with the following supplemental adjustments: (1) more resources being added to the Rocky Mountain region to reflect the revised assessment of the crude oil potential of the Williston basis Bakken formation, based on ARI estimates, and (2) additional inferred resources from the potential for increases of enhanced oil recovery in remaining in-place resources, based on estimates from the Reserves and Production Division of the EIA Office of Oil and Gas.

[33] EIA Annual Energy Outlook 2007, p. 95.

[34] *Ibid*, p. 95.

[35] EIA Assumptions to the Annual Energy Outlook 2007, p. 94. Production is assumed to ramp up to a peak level in 2 to 4 years depending on the size of the field, remain at the peak level until the ratio of cumulative production to initial resource reaches 30 percent, and then decline at an exponential rate of 20 to 30 percent.

Arctic National Wildlife Refuge (ANWR) through the planning horizon, production is expected to decline almost threefold.[36] Estimates include existing producing fields, untapped discovered fields, and fields that are projected to exist, based upon the region's geology.[37]

Discovery Rates

In general, the exploration and production (E&P) of crude oil becomes more profitable when prices increase and development costs decline. In MRN-NEEM, elasticities of production determine supply responses to changes in fuel prices, and higher or lower prices incentivize or discourage E&P activities according to these elasticity parameters. Development costs are a direct function of the rate of improvement in oil extraction technology. Not only can advances in technology reduce production costs from existing reserves, but it can also expand the economically recoverable resource base. The AEO reference case assumes that technology will continue to penetrate at historically observed rates. Technology progress in conventional crude oil parameters in the reference case encompass such things as finding rates, drilling, lease equipment and operating costs, and success rates.

Usage Rates

Oil price movements and economic growth rates most formatively affect levels of fuel oil usage because they provide a direct incentive to either ramp down or up consumption. In contrast, the rate of technological progress in the petroleum industry does not significantly affect domestic oil production in EIA analyses.[38]

1. B.

---

[36] EIA Annual Energy Outlook 2007, p. 95.

[37] EIA Assumptions to the Annual Energy Outlook 2007, p. 99. Expansions in the Prudhoe Bay region count towards the first category, with production having started in 2002. The second category includes fields in the National Petroleum Reserve-Alaska (NPR-A), from which northeastern portions were leased by the Federal government for oil and gas E&P in 1999, 2002, and 2004. The third category accounts for the perceived additional resources on the North Slope of Alaska and in the Beaufort Sea.

[38] EIA Annual Energy Outlook 2007, p. 95.

The profitability and financial condition of producers is a function of the costs of extraction and the prevailing market price for distillate fuel oil. Given a baseline DFO forecast and any policy prescriptions for CO_2 abatement or otherwise, the MRN-NEEM model dynamically models net gains or losses to various production sectors, including oil and gas extraction and oil refining and distribution. For trade-exposed sectors facing international competitors, MRN-NEEM also simulates the leakage of economic activities outside of the United States. 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 that could impact oil producers' bottom line, such as when electricity generators decisively shift away from CO_2-intensive oil.

1. C.

Environmental Factors

The MRN-NEEM model accounts for all environmental regulations currently projected through the planning horizon. This includes Federal caps on SO_2, NO_X, and Hg emissions, as documented in section 4 CSR 240-22.040 (2) (B) 4, and any binding RPS requirements throughout the country. Since fuel oil-burning units emit even greater amounts of CO_2 than more efficient natural gas generators, AmerenUE duly considered the effects of mandatory abatement. The CO_2 policy branches in the probability tree encapsulate what AmerenUE 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_2 policies concern crude oil production sectors.

Competition

The consumption of refined oil products like FO2 in the United States spans across various 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 how oil, gas, and coal are 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.[39] Moreover, higher oil prices could make such tangential enterprises as coal-to-liquids (CTL), oil shale, and GTL economically feasible, resulting in a boom of unconventional oil production. Additionally, LNG contract prices are often tied directly to crude oil prices.[40] The manifold ripple effects in these illustrative examples demonstrate how interrelated natural gas, coal, and fuel oil prices are. Therefore, AmerenUE's integrated resource plan was founded upon projections of key IRP variables from an energy and environment model (MRN-NEEM) capable of properly accounting for macroeconomic feedback effects between electricity demand, electricity prices, and natural gas, coal, and fuel oil prices and consumption levels.

Government Regulation

The base case forecasts for domestic crude oil prices presuppose that royalty relief for natural gas exploration in the offshore Gulf of Mexico conforms to the guidelines stipulated by Section 345 of the Energy Policy Act of 2005 and the Mineral Management Service's (MMS) final rule on the "Oil and Gas Sulphur Operations in the Outer Continental Shelf – Relief or Reduction in Royalty Rates – Deep Gas Provisions."[41] These guidelines shape the E&P costs of the up to 2 million barrels per day the EIA projects to be produced from the Gulf, and as such, are important in establishing base case crude oil prices. Section 345 furnishes royalty relief for oil and gas production in water depths greater than 400 meters for any oil or gas lease sale occurring within 5 years after the enactment, provided minimum volumes of production are satisfied.[42] The MMS final rule grants full relief from royalty payments for leases issued prior to January 1, 2001 with wells drilled to at least 15,000 feet in the shallow

---

[39] EIA Annual Energy Outlook, p.93.

[40] *Ibid*, p. 93.

[41] EIA Assumptions to the Annual Energy Outlook 2007, p. 100.

[42] *Ibid*, p. 100.

waters of the Gulf (again subject to certain minimum volume requirements), relief for up to 5 billion cubic feet of natural gas for unsuccessful wells drilled to at least 18,000 feet, and suspension for volumes of at least 35 billion cubic feet for ultra-deep wells.[43] Although there is considerable uncertainty surrounding the treatment of royalty payments further down the line, the base case crude oil prices assumed a continuation of the present form of law.

1. D.

Both EIA forecasts and MRN-NEEM modeling assume that enough transmission and distribution (T&D) capacity will be built to accommodate projected growth in oil consumption. In so maintaining a constant equilibrium between supply and demand, MRN-NEEM fixes the regional basis differentials that represent the transportation costs from wellhead to end-use location.

1. E.

As first laid out in the response to section 1.D, MRN-NEEM takes for granted any expansions in T&D infrastructure necessary to sustain projected increases in domestic DFO demand. Nevertheless, public opposition to invasive T&D construction activities in their backyard has the potential to stymie crude oil fuel transporters' least-cost operations, which would obviously exert upward pressure on delivered crude oil prices. Depending upon its coverage of the economy, federal CO_2 abatement policies could also penetrate directly into energy-intensive transport industries, like high-GWP (global warming potential) methane operations in pipeline transportation. MRN-NEEM properly simulates the increased costs that crude oil transporters would incur under such a regime. Further, the set of MRN-NEEM modeling scenarios in the probability tree fully spans the range of CO_2 policy uncertainty surrounding the oil transportation and all other energy-intensive sectors.

---

[43] *Ibid*, p. 100.

1. F.

This section is not applicable to crude oil forecasts.

1. G.

AmerenUE expects no explicit restrictions on the use of fuel oil in electricity generation within the IRP time period. More probable restrictions on electricity generation from other fuel types could influence the pattern of natural gas consumption, though. For instance, the Mandates CO_2 policy case envisions a prohibition on new coal-fired plants after 2015. When the existing coal fleet retires, fuel oil will move up in the merit order.

2.

AmerenUE judges the NYMEX light sweet crude oil futures exchange and the 2007 Annual Energy Outlook to be the best forecasts available for basis crude oil and distillate fuel oil prices. CRA International's MRN-NEEM model has been extensively peer-reviewed by such reputable organizations as the International Panel on Climate Change (IPCC) and the Stanford Energy Modeling Forum, and, as such, represents a best-in-class energy and environmental model capable of producing the integrated projections of key IRP variables, including DFO prices, essential to sound resource plan selection.

3.

CRA's extensive past experience in MRN-NEEM modeling has demonstrated that electricity prices, electricity demand, and other pivotal IRP inputs are not sensitive to variations in distillate fuel oil prices. Therefore, distillate fuel oil price branches were not included in the final probability tree.

COAL PRICE FORECAST

Overview:

Unlike natural gas, nuclear, and distillate fuel oil 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 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 63 of the response to section 4 CSR 240-22.040 (2) (B) 4 details the 21 different coal types in the NEEM model. These 21 coals were selected to best represent the major coal sub-markets and production regions in the United States, as presented in Figure 33. Characteristics of each coal used by the NEEM model include (1) the rank of coal, (2) SO_2 content (lb/MMBtu), (3) mercury content (lbs/TBtu), and (4) the energy content per pound of coal:

(1) There are four different ranks of coal within the NEEM coal file. These are bituminous, western bituminous, sub-bituminous, and lignite. These different classifications are required because of the different impacts different fuels have when they are burned.

(2) The SO_2 content is based on information from the Norwest model of the domestic coal supply market.

(3) 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.[44]

[44] Four quarterly data files are available at http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html.

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

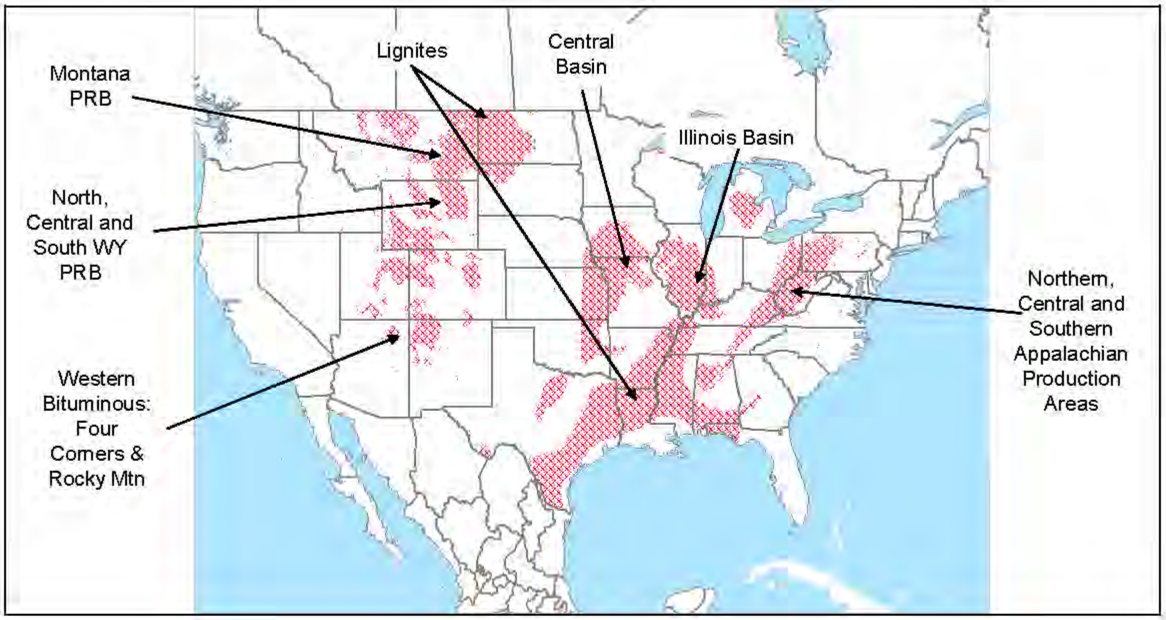

Figure33: NEEM Coal Supply Representation.

For every mine in the nation, Norwest developed models of both production capabilities and minemouth prices per ton of coal production. Using this 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 varied by coal type and were 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 horizon.

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[45] and location. However, both AmerenUE coal units under 200 MW in summer capacity, Meramec 1 and Meramec 2, were modeled separately to provide more precise insights into the AmerenUE coal fleet.

Each coal that can be delivered to and utilized at a unit has a transportation cost from minemouth to 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 dollars expended per ton-mile for that coal. Starting in 2008, these coal delivery costs escalate annually at 2% (in real terms) in order to simulate the increased costs of new rail contracts as existing contracts expire. To be sure, scarcity issues characterize a rail sector that currently dominates the coal transportation market, and this will invariably push delivery costs upward.

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. Consider, for instance, the high CO_2 policy branches of the probability tree, defined by the yellow lines in Figure 34. The higher costs of energy production will pass on through to electricity consumers and depress both overall consumption levels and, in particular, the demand for electricity. In turn, relative to static production costs, the demand for coal will fall, resulting in lower minemouth coal prices.

[45] In any particular NEEM region, coal units with a summer capacity less than 100 MW form one aggregate, those greater than 100 MW and less than 150 MW form a second, and those between 150 MW and 200 MW form a third.

Figure 34 graphically depicts such patterns in minemouth coal prices for coal from the southern Wyoming region of the Powder River Basin. The high CO_2 policy scenarios, especially when coupled with the base gas price and/or the transformed demand cases, sit at the bottom of the price spread. The relative positioning of coal and natural gas prices also contributes to the minemouth prices below. *Ceteris paribus*, higher gas prices will stimulate demand for coal and thrust up coal prices. Appendix F contains tables of minemouth coal prices for coals typically burned by the AmerenUE fleet; that is, the four NEEM coal types from different regions of the Powder River Basin and three NEEM coal types of varying SO_2 content from the Illinois Basin.

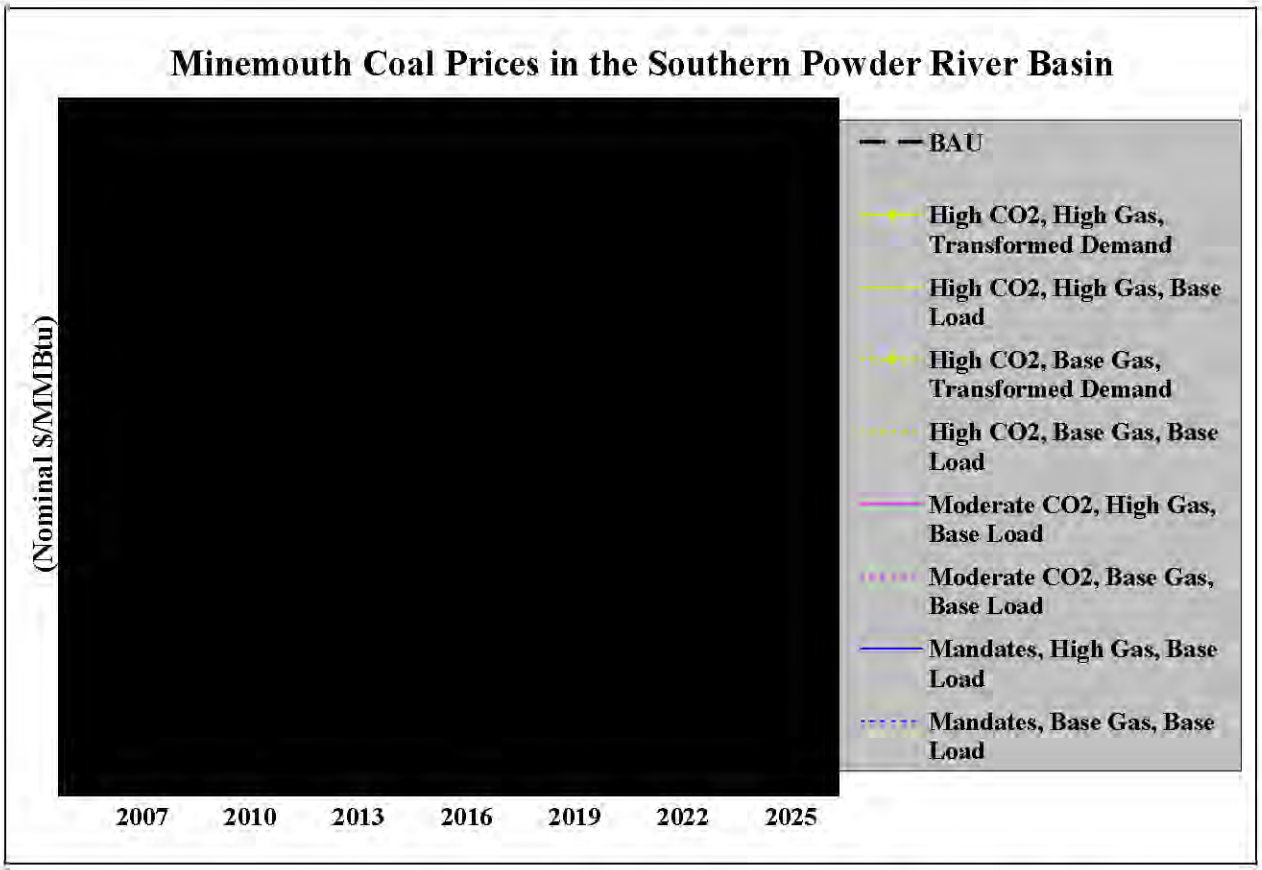

Figure34: Minemouth Coal Prices in the Southern Wyoming Powder River Basin (Nominal $/MMBtu).

Given supply curves for each coal type 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. 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 coal's disadvantage in terms of energy content against its significant advantage in terms of lesser SO_2 content (see Table 63 of section 4 CSR 240-22.040 (2) (B) 4). Especially for units not currently equipped with FGD retrofit technology, switching to PRB coals to reduce SO_2 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 addition of the capability of burning sub-bituminous fuels.[46] 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 United States.

1. A.

As described above, the NEEM model formulates annual supply curves for 21 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 United States, and are generated for each year in the planning horizon. As such, they incorporate estimates of domestic recoverable coal resources and baseline trends in E&P technological

[46] The fuel switch retrofit has a capital cost of between $90/kW and $120/kW for aggregate coal units and $60/kW for non-aggregate coal units. There is also a $0.50/MWh variable cost adder along with a 7% heat rate penalty and a 7% capacity penalty.

improvements. Coal price levels are endogenously calculated to be consistent with the coal consumption levels implied by the supply curves and with allowance prices.

1. B.

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 21 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_2 prices, and natural gas prices, all of which affect the demand for coal.

1. C.

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 materially affect coal producers are represented in the probability tree (*e.g.*, the Mandates scenario, which prohibits new coal builds after 2015 and sets an RPS starting in 2010).

1. D.

The matrix of transportation costs described above tabulates the costs of the up to four delivery options (truck, rail, barge, and mixed) available to each NEEM coal unit. This matrix is based upon historical data from the Platts CoalDat database. Further, transportation costs increase at a 2% per year rate (in real terms) to replicate what AmerenUE 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.

1. E.

As first laid out in the response to section 1.D, 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_2 abatement policies could also penetrate directly into energy-intensive coal transport industries, like railroads. MRN-NEEM properly simulates the increased costs that coal rail transporters would incur under such a regime. Further, the set of MRN-NEEM modeling scenarios in the probability tree fully spans the range of CO_2 policy uncertainty surrounding the coal transportation and all other energy-intensive sectors.

1. F.

This section is not applicable to coal price forecasts.

1. G.

In the place of a market-based approach to CO_2 abatement, AmerenUE management envisaged a situation where a patchwork of federal mandates accumulated to the point where an emissions trading scheme becomes unnecessary. As presented in Figure 31 of section 4 CSR 240-22.040(2) , in-house CO_2 policy experts assigned a nonzero probability to cap-and-trade never eventuating, due to a realistic assessment of the economic costs to vital American industries and to the inertia enveloping an equitable allocation of free allowances across vulnerable sectors, among other reasons. If this were to happen, then one of the first dominos to fall would likely be coal-based generation, as it emits more CO_2 than any other form of electricity generation. The Mandates scenario in the probability tree prohibits the construction of new coal facilities without carbon capture and sequestration capabilities after the year 2015.

2.

CRA International's MRN-NEEM model has been extensively peer-reviewed by such reputable organizations as the International Panel on Climate Change (IPCC) and the Stanford Energy Modeling Forum, and, as such, represents a best-in-class energy and environmental model capable of producing the integrated projections of key IRP variables, including coal prices, essential to sound resource plan selection. In addition, Norwest represents one of the world's foremost and most fully-integrated energy and natural resource consultancies, with over thirty years of experience in the American coal industry.

3.

See the discussion above Figure 31 detailing how coal demand responds to different CO_2 policy and natural gas price levels, both of which are probabilistically represented in the scenario tree. In addition, keeping all other things equal, the decreased demand forecasts in the transformed demand branches will result in coal prices dropping, especially in the later years of the IRP horizon when assumed demand reductions due to energy efficiency advances are most pronounced.

4 CSR 240-22.040 (8) (B)

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

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

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

<u>Fossil and Renewable Resources</u>

The capital cost estimating method was based on Black & Veatch estimating templates and relies upon historical databases and continuously updated cost data taken from Black & Veatch's involvement in the design and construction of all types of power plants. The cost estimates are intended to have an accuracy between +30 to -20 percent. The probability distribution for this accuracy range is shown in Table 66.

Table 66
Capital Cost Uncertainty Distribution

Deviation	30	15	0	-10	-20
Probability	5%	25%	40%	25%	5%

Nuclear

AmerenUE retained Black & Veatch Corporation to develop capital cost estimates for the nuclear technology. Black & Veatch with our over 9,000 employees is one of the leading and largest engineering firms in the world providing services to the nuclear industry. Black & Veatch is currently providing engineering, procurement, and construction (EPC) services for the Lungmen Nuclear Project, one of the very few nuclear plants in the world that is currently under construction. Black & Veatch is also the EPC contractor for numerous coal and natural gas units throughout the country providing current costs for commodities and labor.

This cost estimate is for the development of a single unit US-EPR Nuclear Power Plant located at the AmerenUE Callaway site. The expected cost estimate and its associated ranges and probabilities are provided in Table 67.

Table 67
Total EPC + Owner's Costs including Transmission
(Overnight 2007 $ w/o AFUDC)

	Value	Probability	Comments
[redacted]			

The ranges and probabilities were developed by Black & Veatch after consideration of historical cost escalation and consideration of current issues associated with the costs of large power plant projects.

There are a number of critical uncertain factors associated with the cost of constructing the US-EPR. The first is the long lead time before construction begins and the long construction period. Labor and commodity costs could increase or decrease; however, the probability of increases appears more probable than decreases. Major factors affecting these costs include continued economic development in Asia increasing the demand for commodities and the aging construction labor force in the US resulting in lower numbers of craft labor and reduced productivity from the available labor force due to lower quality of labor of the remaining labor force.

The second uncertain factor is the estimated labor and material quantities. As the detailed design develops and EPR's are constructed, labor and material quantities will become better known. Although conservative estimates are made of quantities, as designs mature, the probability that quantities increase generally outweighs the probability that quantities decrease. A third uncertain factor is regulatory change and delays. It is generally unlikely that regulatory changes will reduce cost. The US-EPR, however, has been designed to accommodate significant regulatory changes. The most prominent example is the consideration of aircraft impacts following 9/11.

A fourth uncertainty factor is the reduction in costs due to improved technology for construction. This could include improved construction techniques, improved sequencing, or better technology. This uncertainty factor will only contribute to decreasing capital costs.

Pump Storage

The cost data is included in the 2007 Supplemental Concept Study Report prepared by Paul C. Rizzo Associates, Inc.

4 CSR 240-22.040 (8) (C)

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

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

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

Fossil and Renewable Resources

Black & Veatch estimates fossil and renewable resources O&M costs by applying its knowledge and experience of operating plants. Plant O&M strategies vary somewhat by utility, so the expected accuracies of the fixed and variable components of annual O&M costs are not the same.

Fixed O&M costs are largely a function of the staffing required to operate the plant. The number of staff required to operate a given plant may vary, but for a given size of a given generation technology, the number of staff can be estimated with good accuracy. Black & Veatch characterized the estimated fixed O&M cost as being between +20 and -20 percent, as shown in Table 68.

Table 68
Fixed O&M Cost Uncertainty Distribution

Deviation	30	15	0	-10	-20
Probability	5%	25%	40%	25%	5%

Variable costs are more difficult to accurately estimate without detailed knowledge of how a utility operates its plants and the condition of the plants being operated. For screening-level estimates such as those done for this study, it is not reasonable to get into that level of detail. Instead, Black & Veatch estimated the variable costs assuming that a new plant would be built in accordance with the dispatch stated. To characterize the probability distribution of the variable O&M costs for the screened technologies, variable O&M cost data were examined from Energy Velocity. Data for the US fleets of each of the generation technologies were downloaded. Distributions around a mean value for each technology were identified. The mean was assumed to correspond to the estimated value for this study, which is referenced in Table 69 as "Base." The plants included in the database are expected to operate across broad spectra of dispatch and O&M strategies, therefore resulting in the widest variation that could be expected. The distributions are expected to characterize the potential variations that may be experienced by AmerenUE. The renewable variable O&M cost uncertainty distribution is provided in Table 69

Table 69
Variable O&M Cost Uncertainty Distribution

850 MW Supercritical PC				
Deviation	-60%	Base	40%	80%
Probability	15%	50%	25%	10%
600 MW IGCC				
Deviation	-60%	Base	40%	80%
Probability	15%	50%	25%	10%
LMS 100				
Deviation	-73%	Base	100%	
Probability	35%	45%	25%	
7FA				
Deviation	-50%	Base	50%	
Probability	25%	50%	25%	
2x1 7FB				
Deviation	-50%	Base	33%	83%
Probability	25%	45%	25%	5%

Table 70 Variable O&M Cost Uncertainty Distribution				
Biomass Combustion - Standalone				
Deviation	-50%	Base	50%	
Probability	25%	50%	25%	
Biomass Combustion - Cofiring				
Deviation	-60%	Base	40%	80%
Probability	15%	50%	25%	10%
LFG – Reciprocating Engine				
Deviation	-50%	Base	50%	
Probability	25%	50%	25%	
LFG – Combustion Turbine				
Deviation	-50%	Base	50%	
Probability	25%	50%	25%	
Hydroelectric – Run of River				
Deviation	-50%	Base	50%	
Probability	25%	50%	25%	
Wind				
Deviation	-50%	Base	50%	
Probability	25%	50%	25%	

Nuclear

Black & Veatch estimated the expected fixed O&M cost of [redacted]/MW-year and non-fuel variable O&M cost of [redacted]/MWh based on an estimated [redacted] total onsite and offsite staff and an assumed [redacted] percent capacity factor of the unit. The expected fixed and variable O&M costs along with ranges and probabilities are presented in Table 71.

Table 71 Fixed and Non-Fuel Variable O&M (2007 $/MW-year)
Fixed O&M (2007 $/MW-year)
[redacted]
Non-Fuel Variable O&M (2007 $/MWh)
[redacted]

Black & Veatch considered many critical uncertain factors in developing the ranges and probabilities in developing the estimates of for fixed and variable O&M including consideration of O&M costs for existing operating nuclear units. Black & Veatch especially focused on the O&M costs for the existing the Callaway Unit and how the operations and maintenance of the US-EPR would be integrated with Callaway Unit 1 operation and maintenance. The critical uncertain factors are discussed below.

Staffing is the biggest driver of fixed O&M costs. Historically, staffing has varied considerably from plant to plant. A significant part of this variation hinges on the numbers of utility staff versus the number of contract staff; however, whether the staff is utility staff or contract staff, the costs still accrue. The detailed comparison of staff for the Callaway 1 and the US-EPR is presented in Table 72.

Table 72 Staffing Comparison for Onsite and Offsite Personnel			
EUCG Account	**Description**	**Existing Callaway Unit 1**	**Proposed US-EPR Addition to Existing Site**
CM001A	Design / Mods / Technical Engr	36	17
CM001B	Nuclear Fuels / Reactor Engr	3	12
CM002A	Computer Engr	-	2
CM002B	Project Management	-	2
CMADM	Administrative Support	7	4
CMMGMT	Configuration Management (Mgmt)	4	6
CMTOT	**Total – Configuration Management**	**49**	**43**
ER001	Plant Engineering	86	25
ER002	Nondestructive Exams (NDE)	1	1
ERADM	Administrative Support	-	-

Table 72
Staffing Comparison for Onsite and Offsite Personnel

EUCG Account	Description	Existing Callaway Unit 1	Proposed US-EPR Addition to Existing Site
ERMGMT	Equipment Reliability (Mgmt)	6	4
ERTOT	**Total - Equipment Reliability**	**93**	**30**
LP001	Security	87	23
LP002	QA and Corrective Action Program	9	4
LP003	Safety / Health	4	1
LP004	Licensing	4	5
LP005	Emergency Preparedness	2	2
LP006	Fire Protection	-	-
LPADM	Administrative Support	4	2
LPMGMT	Loss Prevention (Mgmt)	14	6
LPTOT	**Total - Loss Prevention**	**122**	**43**

Table 72 Staffing Comparison for Onsite and Offsite Personnel			
EUCG Account	**Description**	**Existing Callaway Unit 1**	**Proposed US-EPR Addition to Existing Site**
MS001	Materials Mgmt / Warehouse	15	8
MS002A	Contracts and Purchasing	2	-
MS002B	Procurement Engineering	1	-
MSADM	Administrative Support	1	-
MSMGMT	Materials and Services (Mgmt)	3	1
MSTOT	**Total - Materials and Services**	**21**	**9**
OP001A	Operations	69	47
OP001B	Operations Support	17	10
OP002	Environmental	1	-
OP003	Chemistry	12	13
OPADM	Administrative Support	5	4

Table 72 Staffing Comparison for Onsite and Offsite Personnel			
EUCG Account	**Description**	**Existing Callaway Unit 1**	**Proposed US-EPR Addition to Existing Site**
OPMGMT	Operate Plant (Mgmt)	10	8
OPTOT	**Total - Operate Plant**	**114**	**82**
SS001	Information Services	8	10
SS002	Financial Services	3	1
SS003	Document Control / Records	7	3
SS004	Human Resources	2	1
SS005	Facilities	20	12
SS006	Communications	-	-
SSADM	Administrative Support	1	1
SSASST	Management Assistance	-	-
SSMGMT	Support Services Management	3	-

Table 72 Staffing Comparison for Onsite and Offsite Personnel			
EUCG Account	**Description**	**Existing Callaway Unit 1**	**Proposed US-EPR Addition to Existing Site**
SSTOT	**Total - Management and Support Services**	**43**	**28**
T001	Training (Mgmt)	15	11
TADM	Administrative Support	3	1
TMGMT	Training (Mgmt)	4	-
TTOT	**Total – Training**	**21**	**12**
WM001A	Outage Management	2	2
WM001B	Maintenance / Construction Support	18	3
WM002A	Planning	6	5
WM002B	Scheduling	4	4
WM003A	Quality Control	7	5
WM003B	Electrical Maintenance	40	32
WM003C	I&C Maintenance	40	34

Table 72 Staffing Comparison for Onsite and Offsite Personnel			
EUCG Account	**Description**	**Existing Callaway Unit 1**	**Proposed US-EPR Addition to Existing Site**
WM003D	Mechanical Maintenance	62	62
WM003E	Maintenance / Construction Other	11	5
WM007	RP – Support	11	8
WM008	Radwaste and RP Direct	31	28
WMADM	Administrative Support	10	6
WMMGMT	Work Management (Mgmt)	12	3
WMTOT	**Total - Work Management**	**255**	**197**
OFFTOT	**Total - Officers / Executives**	**1**	-
STAFFTOT	**Total – Staffing**	**719**	**444**

One of the uncertainty factors that has the greatest impact on O&M cost is the number of staff required. A larger number of staff may be required for a number of reasons. Among these reasons are the productivity of staff is below what is estimated, radiation exposure is higher than anticipated resulting in more staff being required, more or more maintenance is required than estimated. With the US-EPR, there are substantial opportunities for reductions in staff due to the UniStar concept of fleet operation. Standardization should reduce maintenance requirements and increase efficiency.

Pump Storage

The cost data is included in the 2007 Supplemental Concept Study Report prepared by Paul C. Rizzo Associates, Inc.

4 CSR 240-22.040 (8) (D)

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

1. **Forecasts of the future value of emission allowances shall be obtained from a qualified consulting firm or other source with expert knowledge of the factors affecting allowance prices.**
2. **The provider of the forecast shall be required to identify the critical uncertain factors that may cause the value of allowances to change significantly and to provide a range of forecasts and an associated subjective probability distribution that affects this uncertainty;**

The response to section CSR 240-22.040 (2) (B) 4 describes how SO_2 allowance prices are formed in the NEEM model. To reiterate, NEEM dynamically chooses optimal 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 reserve margin requirements and complying with all environmental regulations. NEEM allows for banking, so emissions in a given year do not necessarily match the prescribed annual limits of the program, as given previously in Table 61 of section CSR 240-22.040 (2) (B) 4. The degree to which the prescribed caps are binding (*i.e.*, the level of emissions) determines optimal banking patterns, and, in turn, the equilibrium allowance price. The interplay between the above determinants of SO_2 emissions from the domestic coal fleet and the caps prescribed by the joint Title IV/Clean Air Interstate Rule establishes SO_2 allowance prices equal to the marginal cost of removing one more allowance.[47] Note that because the Title IV/CAIR rule covers a national market, all AmerenUE generating facilities face the same SO_2 allowance price.

[47] Title IV melds into the CAIR SO_2 program beginning in 2010 when units in the CAIR region are required to submit two allowances for every ton emitted. This increases to 2.86 allowances per ton in 2015. As such, the marginal abatement cost of removing one more allowance prior to 2010 is equivalent to the marginal cost of reducing an incremental ton of SO_2.

The construction of the probability tree identified the critical uncertain factors that AmerenUE decision makers deemed could most significantly affect key inputs to the risk analysis and strategy selection phases of the IRP process. Among these critical uncertain factors are CO_2 policy directions, natural gas prices, and load growth forecasts, and among the resulting key inputs are projections of SO_2 allowance prices. Having winnowed out the uncertain variables that would comprise the probability tree, CRA and AmerenUE jointly cultivated a set of cases to fully reflect a reasonable range of each uncertainty. These cases are as follows:

1. CO_2 Policy Uncertainty[48] -
    a. "High CO_2 Prices," starting at [redacted] short ton of CO_2 (in nominal dollars) in 2012 and rising at [redacted] per year in real terms,
    b. "Moderate CO_2 Prices," starting at [redacted] short ton of CO_2 (in nominal dollars) in 2012 and rising at [redacted] per year in real terms,
    c. "Mandates," which would, in the place of a formal cap-and-trade scheme, be characterized by the following prescriptive regulations:
        i. A federal RPS[49] requiring 20% of electricity demand be met through renewable energy sources by 2020, but with a REC price ceiling of $30/MWh (in 2003 dollars),
        ii. A prohibition on new coal builds without carbon capture and sequestration capabilities after 2015,
    d. "BAU," which would be the continuation of the present world with no meaningful GHG policy in effect;
2. Natural Gas Prices[50] –
    a. "Base Gas Prices," which are based on monthly NYMEX futures prices at Henry Hub through 2012, 2007 EIA Annual Energy Outlook projections

---

[48] See the responses to section 4 CSR 240-22.040 (2) (B) for a more detailed exposition.

[49] See Figure 29 in the response to section 4 CSR 240-22.040 (2) (B) 2.

[50] See the responses to section 4 CSR 240-22.040 (8) for a more detailed exposition.

of Henry Hub natural gas prices from 2015 through 2030, and a linear interpolation between these two sources from 2013 through 2014,

b. "High Gas Prices," which assumes base case gas prices through 2012 and then a linear annual growth to a wellhead natural gas price of $8.60/Mcf (in 2007 dollars) in 2030;

3. Load Growth Forecasts[51] –
   a. "Base Load Growth," which are based on projections from the NERC ES&D 10 Year Forecast from 2007 through 2014 and the compound average annual growth rate from 2009 to 2014 for all subsequent years,
   b. "Transformed Demand," in which energy efficiency advances result in a 20% reduction in on-grid demand from base load growth by 2030.

Subjective probability distributions were then elicited from AmerenUE decision makers with expertise in each of the above subject areas.

Before finalizing the structure of the scenario tree with associated probabilities, CRA assessed the potential to eliminate certain permutations of the set of critical uncertain variables from the probability tree. The criteria for folding certain scenarios onto other branches consisted of there being (1) a low combined probability of that set of events represented in the branch occurring and (2) similarity across the key IRP inputs with a scenario assigned a higher probability. The end result of this process is the probability tree given in Figure 35. As shown, variation in the three critical uncertain factors is represented by nine sets of integrated modeling results, or scenarios. These scenarios produced the spread of SO_2 allowance prices observable in Figure 34 of section CSR 240-22.040 (2) (B) 4.

[51] See the response to section 4 CSR 240-22.030 (7) for a more detailed exposition.

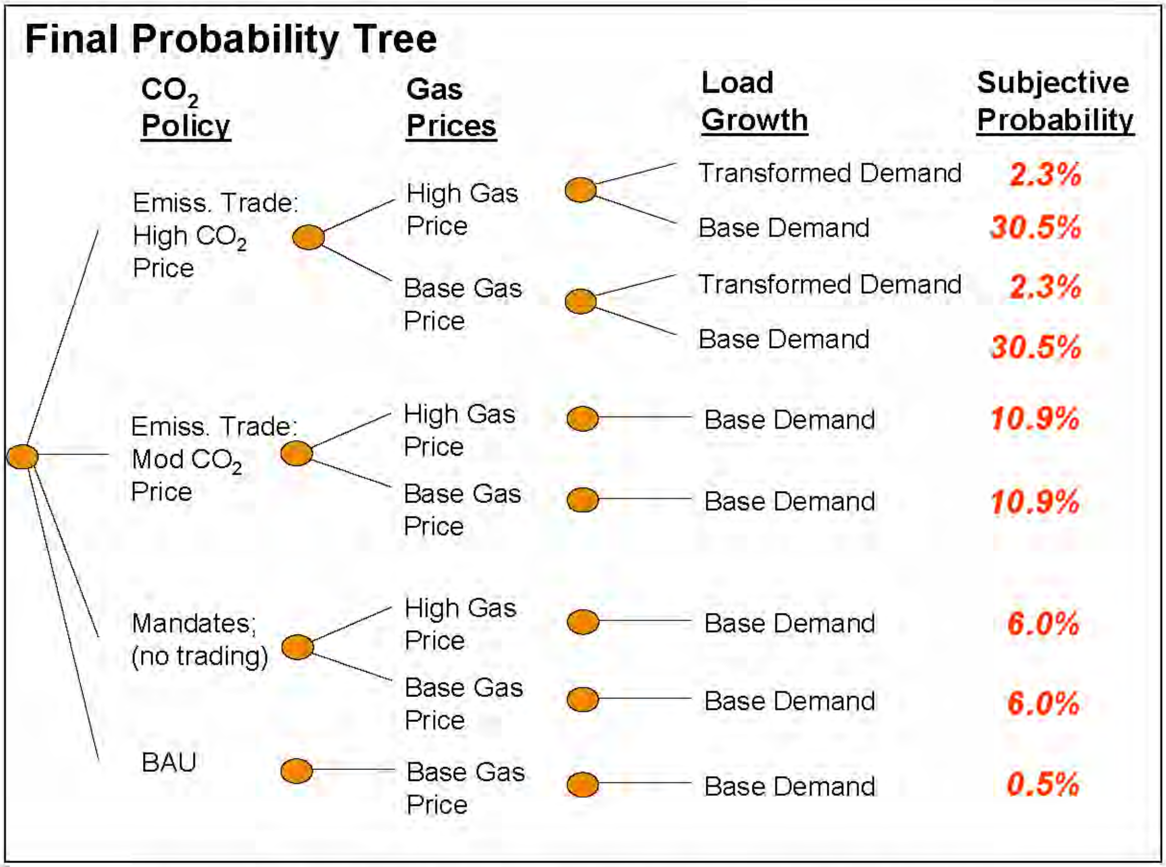

Figure35: Final Probability Tree with Subjective Probabilities.

4 CSR 240-22.040 (8) (E)

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

Since there are no leased or rented facilities included in this option, annual fixed charges are not applicable.

4 CSR 240-22.040 (9)

Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall furnish at least the following information:

4 CSR 240-22.040 (9) (A)

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

1. **The calculated values of the utility cost and the probable environmental cost for each resource option and the rankings based on these costs;**
2. **Identification of candidate resource options that may be included in alternative resource plans; and**
3. **An explanation of the reasons why each supply-side resource option rejected as a result of the screening analysis was not included as a candidate resource option;**

Fossil and Renewable Resources

A summary table of the resources identified pursuant to section (1) is provided in the Characterization Table of 4 CSR 240-22.040 Appendix A for fossil and of 4 CSR 240-22.040 Appendix B for renewables. The calculated utility costs and probable environmental costs are provided in Sections (2) (A) and (2) (B), respectively. The candidate resource options are identified in section 2(C). Explanations for rejecting potential resource options are identified in Table 2 and 22 in Section (1).

Nuclear

Table 73 identifies the nuclear resource options that were evaluated and their corresponding rankings. Tables 74 and 75 present the detailed capital costs and O&M costs associated with the US-EPR which was the selected nuclear technology. The capital and O&M costs include the probable environmental costs associated with the technology, and this analysis only addresses the nuclear technology option which is the US-EPR.

Table 73 illustrates the categories which were used to screen each new nuclear generation option. Based on the criteria used for the Phase I screening process, the US-EPR, ABWR, and AP1000 ranked 1, 2, and 3, respectively. During Phase II, these three technologies were further evaluated based on AmerenUE's needs which are discussed below.

Safety. In August 1995, the NRC adopted the use of Probabilistic Risk Analysis (PRA) technology in all regulatory matters to the extent supported by the state of art in PRA methods and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy. In particular, the US NRC has established goals for core damage frequency (CDF), large release frequency (LRF), and containment performance. The US-EPR, the ABWR, and the AP1000 each exceed the NRC safety requirements. PRA analysis indicates that each of the three nuclear generation technologies represent order of magnitude improvements in safety compared to previous generation nuclear technologies.

As noted earlier, both the ABWR and the AP1000 may require design changes to enhance their abilities to withstand impact from commercial airplanes, depending on the outcome of NRC current consideration of rulemaking in that area. The US-EPR provides a greater degree of aircraft impact resistance than either the ABWR or AP1000.

Reliability of Technology. The three nuclear generation technologies ranking highest in the screening analysis incorporate simplifications in design compared to the previous generation of technologies from which they evolved. This simplification contributes to the expected availability of the US-EPR, the ABWR, and the AP1000. The US-EPR is expected to have a lifetime availability of approximately 94 percent, higher than the expected lifetime availability of either the ABWR (90 percent) or the AP1000 (93 percent). The increased availability of the US-EPR will provide AmerenUE with more low-cost, baseload generation than either the ABWR or AP1000.

Cost of Generation. A number of factors contribute to the cost of generation associated with the three nuclear generation technologies considered in this report. Economies of scale in capital and operating costs, consistency with the existing Callaway PWR unit, expected availability, fleet operation, flexibility in refueling cycles, qualification for Production Tax Credits, the potential for mitigation of first of a kind issues, and efficiency have all previously been discussed and characterized for each of the three nuclear technologies. When considering all of these factors in conjunction with one another (which are discussed in the following sections), the US-EPR overall generally has advantages over the ABWR and AP1000.

Production Tax Credits. The US-EPR, ABWR, and AP1000 would each potentially allow AmerenUE to obtain Production Tax Credits under the Energy Policy Act of 2005. As discussed throughout previous sections of this report, in order to qualify for Production Tax Credits under the Energy Policy Act of 2005, three specific milestones must be met including COLA submission before December 31, 2008, first pour of safety-related concrete before January 1, 2014, and commercial operation prior to January 1, 2021. The US-EPR and the AP1000 provide a greater degree of assurance to meet the deadlines required to qualify for Production Tax Credits than the ABWR due to the benefits associated with UniStar and NuStart.

There are two factors that may adversely impact the ability of the AP1000 to meet the COLA and first safety-related concrete pour milestones required to qualify for Production Tax Credits. The first factor relates to Westinghouse's ability to accommodate AmerenUE's needs in conjunction with existing orders for several AP1000 units which would be ahead of AmerenUE's order if the AP1000 was selected by AmerenUE. The second factor relates to the significant number of requests for additional information that Westinghouse has received in response to its safety-related redesign of the AP1000. Confidential discussions between AmerenUE and Westinghouse executives did not provide AmerenUE with adequate assurance that these factors would not affect the required schedule for obtaining the Production Tax Credits.

Of the three nuclear generation technologies considered, the US-EPR would allow AmerenUE to obtain the greatest benefits from savings associated with Production Tax Credits due to the increased capacity and high availability of the US-EPR compared to the ABWR and AP1000.

Economies of Scale. As the largest of the three nuclear alternatives being considered by AmerenUE, the US-EPR provides for increased benefits from economies of scale. The increased forecasted availability of the US-EPR and AP1000 compared to the ABWR also reduce generation costs, allowing the costs of the new unit to be distributed over a greater number of MWh.

[redacted]

Fleet Operation and Standardization. While AmerenUE would be able to participate in technology-specific owner's groups and overall nuclear industry associations regardless of whether the US-EPR, the ABWR or the AP1000 was selected, the fleet concept behind the US-EPR (UniStar) and the AP1000 (NuStart) would provide significant benefits to AmerenUE since they currently operate only one unit and do not have the benefit of fleet efficiencies. For the US-EPR, UniStar will provide substantial savings in engineering, licensing, maintenance, operations and modifications, and spare parts costs. EdF will provide technical expertise that will benefit design, licensing, construction, and operation of the US-EPR. Reliability of the US-EPR will also be enhanced by UniStar, as spare parts will be more readily available and it will not be necessary for AmerenUE to purchase a complete set in advance or store them on site. UniStar has also indicated that their services will include provision of qualified and trained operators for their members, thus providing the flexibility for AmerenUE to subcontract these responsibilities should that be determined to be economically beneficial. For the AP1000, NuStart will provide benefits related to licensing and design. AmerenUE has indicated that confidential discussions with Westinghouse executives have not provided assurances that the benefits of NuStart would exceed the benefits that the US-EPR would realize from UniStar.

Consistency with the Operating Callaway Unit. In selecting which nuclear technology to characterize in the IRP, AmerenUE should consider how the new unit may be able to capitalize on commonalities with the existing Callaway Unit. AmerenUE's history and experience with PWR technology will result in increased operating efficiencies and lower costs if either a US-EPR or AP1000 was constructed at Callaway. Both the US-EPR and AP1000 are based on previous generation PWR nuclear technology which will allow AmerenUE to transfer experience gained through current operations, although the US-EPR is closer in design to a traditional PWR than the AP1000. Due to significant differences between BWR and PWR technologies, construction of an ABWR will necessitate greater training and possibly more O&M staff.

Refueling Cycle. The US-EPR and ABWR will both provide AmerenUE flexibility in determining the optimal refueling cycle, thereby reducing associated refueling outage costs. The US-EPR and ABWR technologies each have up to a 24 month refueling cycle, while the AP1000 refueling cycle is limited to 18 months. The added flexibility of the refueling cycle allows optimization based on fuel pricing, scheduling, availability and cost of replacement generation, and system demand. Conversely, the shorter refueling cycle of the AP1000 may necessitate less than optimal refueling outage schedules and coordination of outages with the other operating unit.

Assurance of Ability to License. Both the ABWR and AP1000 have received final Design Certification from the NRC. However, revisions to the design of both the ABWR and AP1000 continue and the NRC has not yet granted final Design Certification for the revisions. As discussed previously within this report, the time required for re-certification, including responding to the significant number of requests for additional information, may adversely impact the licensing timeframe associated with the AP1000.

The US-EPR has not yet received Design Certification, but is scheduled to do so within a timeframe to support construction of a unit in time to meet AmerenUE's needs.

There are currently no operating US-EPR or AP1000 units either in the US or throughout the world, but several of each technology are in various stages of the construction or planning. It should be noted that the US-EPR and AP1000 are both based on the demonstrated technology used in existing PWR units. There are a total of seven operating ABWR units, and several in various stages of the construction or planning stages throughout the world, including the US. The ABWR is based on the demonstrated technology used in existing BWR units. Overall, from the perspective of NRC experience with each of the three technologies, the US-EPR, the ABWR, and the AP1000 can be considered similar to one another.

Technology Status. The US-EPR, the ABWR, and the AP1000 have each evolved from previous generation PWR and BWR technologies. Each of the three nuclear technologies represents improvements over previous generation technologies.

Construction Schedule. The US-EPR, the ABWR, and the AP1000 each have comparable construction schedules and timeframes between first safety concrete pour and fuel load, and fuel load to commercial operation. It is expected that any of the three technologies could be constructed in time to meet AmerenUE's requirements.

The fleet concept and consortium support behind both the US-EPR and the AP1000 provide increased assurances that not only the selected technology will be constructed on schedule to support AmerenUE's needs, but will also achieve the milestones required to qualify for the Energy Policy Act Production Tax Credits.

The previous sections identified AmerenUE's requirements and discussed each of the three nuclear generation technology alternatives' ability to satisfy these requirements. The US-EPR, the ABWR, and the AP1000 are each likely capable of meeting most of AmerenUE's requirements. Based on the information presented previously, it appears that in several areas the US-EPR better meets AmerenUE's unique requirements than either the ABWR or the AP1000. Based on this conclusion, the US-EPR has been chosen as the candidate resource option for AmerenUE.

Table 73
Screening Results

	Capital Cost			Energy Policy Act Benefits			Development Risk			Ability to License			Staffing			Safety and Environmental		
	15%			10%			10%			10%			5%			15%		
	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total
ABWR	[redacted]																	
ACR-1000	[redacted]																	
AP1000	[redacted]																	
ESBWR	[redacted]																	
PBMR	[redacted]																	
US-APWR	[redacted]																	
US-EPR	[redacted]																	

Table 73 (cont)
Screening Results

	Fuel Cost and Availability			O&M Cost			Economy of Scale			Construction Schedule			Grand Total	Rank
	10%			15%			5%			5%				
	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total	Criteria Score	Wt	Category Total		
ABWR	[redacted]													
ACR-1000	[redacted]													
AP1000	[redacted]													
ESBWR	[redacted]													
PBMR	[redacted]													
US-APWR	[redacted]													
US-EPR	[redacted]													

Table 74 Total EPC + Owner's Costs including Transmission (Overnight 2007 $ w/o AFUDC)			
	Value	Probability	Comments
[redacted]			

Table 75 Fixed and Non-Fuel Variable O&M (2007 $/MW-year)
Fixed O&M (2007 $/MW-year)
[redacted]
Non-Fuel Variable O&M (2007 $/MWh)
[redacted]

4 CSR 240-22.040 (9) (B)

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

For fossil and renewable resource a list of candidate resource options for which forecasts, estimates, and probability distributions have been developed are presented in Section (2)(C). The probability distribution are presented in Section (8).

The table 76 below illustrates the probabilities and distributions associated with the US-EPR.

Table 76 Distributions and Probabilities of the US-EPR			
Parameter	Value	Probability (if applicable)	Comments
[redacted]			

Table 76
Distributions and Probabilities of the US-EPR

Parameter	Value	Probability (if applicable)	Comments
[redacted]			

4 CSR 240-22.040 (9) (C)

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

For Fossil and Renewable Resources, the results of the uncertainty analysis are presented in Section (8).

For Nuclear, the summary of the results of the uncertainty analysis is presented in Table 76.

4 CSR 240-22.040 (9) (D)

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

The response to Section (2)(B) clarifies how SO_2, NO_X, and Hg allowance prices are formulated in the NEEM model, and also lists the sources of the assumed retrofit technology costs and characteristics.

Fossil:

Estimates of mitigation costs provided in this supply side resource analysis are confined to CO_2 mitigation. These are presented in terms of estimated capital and O&M for selected coal fueled technologies. These costs are provided in the Characterization Table of 4 CSR 240-22.040 Appendix A.

Renewable Resources:

No mitigation costs we included with in the supply-side resource.

Nuclear:

The mitigation cost estimates include several areas. AmerenUE's work on preparing a Combined Construction and Operating License Application (COLA) decreases the time until the construction can be started and meets part of the requirements for obtaining the Production Tax Credits. Decreasing the time until construction can start provides greater certainty in overall construction cost. The estimated cost for the COLA is $70,000,000.

Another area of mitigation costs is that the capital cost estimate was developed based on an engineering, procurement, and construction (EPC) cost estimate. With and

EPC cost estimate, the utility obtains a guaranteed cost for the plant and the contractor accepts all risks associated with cost increases. For this mitigation of cost increases, the EPC contractor includes a contingency for unidentified costs and a profit margin. The contingency included in the EPC estimate is [redacted] The EPC profit included in the cost estimate is [redacted]

Another mitigation area is the use of the existing Callaway site for the US-EPR. The use of the existing site saves costs for a new site and eliminates uncertainty with respect to site conditions and licensing uncertainty. While the cost estimates were developed assuming the Callaway site, a new site could have added $10 million to $30 million to the cost estimate. The additional costs could be considerably more if licensing uncertainty delayed the project.

Another cost mitigation measure is the ordering of large forgings. There is only one company in the world capable of making the forgings necessary for the US-EPR. AmerenUE has ordered the forgings for the US-EPR. By ordering the forgings, AmerenUE maintains its ability to complete the project timely and to maximize the Production Tax Credits. The cost of the forgings is [redacted] Even if the plant is not constructed, the forgings could be sold to someone else building an US-EPR.

Another type of cost mitigation could entail AmerenUE selling partial ownership in the unit to another party. As a joint owner, AmerenUE would still obtain all the advantages of economies of scale in both capital costs and operating costs, but in effect have a smaller unit with a proportionately smaller capital and operating cost at the same per unit ($/KW) cost as the whole unit. The competitiveness of the US-EPR ensures that there would be a ready market of potential joint owners willing to participate at cost or even potentially at a margin above cost.