2. Planning Environment

Highlights

- *General economic conditions suggest sustained growth that is modest by historical standards, resulting in lower-than-historical load growth when combined with increasing energy efficiency.*
- *Natural gas prices will continue to be driven by large domestic supplies of shale gas and approximate a range of $4 - $6 per MMBtu in today's dollars.*
- *Environmental regulations coupled with relatively low gas prices and slow load growth will continue to drive additional retirements of coal-fired generation*
- *Ameren Missouri has developed and modeled 15 scenarios, comprising ranges of values for key variables that drive wholesale power prices, for use in evaluating its alternative resource plans.*

In evaluating our customers' future energy needs and the various options to meet them, it is necessary to consider the current and future conditions under which we must meet those needs. Ameren Missouri continuously monitors the conditions and circumstances that can drive or influence our decisions. Collectively, we refer to these conditions and circumstances as the "Planning Environment." This Chapter describes the basis for the assumptions used in our analysis of resource options and the performance of the alternative resource plans described in Chapter 9.

2.1 General Economic Conditions

General economic conditions have slowly improved in the U.S. over the last few years following the severe recession that occurred in the 2007-2009 timeframe. The nature of the financial crisis that coincided with the recession also caused the recovery from that recession to be unusually slow. Businesses and households were extremely risk averse and capital was difficult for businesses to access for an extended period of time following the financial crisis. After several years of very low interest rates and stimulative monetary policies enacted by the Federal Reserve, the economy has generally overcome the most significant headwinds left by the recession, and GDP is once again growing.

For the decades leading up to the 2007-2009 recession, GDP grew nationally at a pace of approximately 3% per year. Ameren Missouri's expectations are for a return to GDP growth at or near that long term pre-recession trend for a short period of time followed by relatively stable longer term growth, but at a slower pace than has been observed historically, in the 2-2.5% range per year. Generally, demographic factors will provide the greatest long term challenge to growth, as the growth in the labor force, one of the key components of long-term economic growth, is expected to be below its historical rate as the Baby Boomer generation begins to enter retirement. Also, the federal budget picture in the U.S. poses risks to the country's long-term economic health if reforms are not made to either tax or spending policies in order to bring the national debt to GDP ratio onto a stable trajectory. That said, our base expectation is for economic growth at the national level to continue throughout the planning horizon of the IRP at a steady but modest pace by historical standards, subject to normal business cycle variability.

Ameren Missouri's outlook for the local economy of its service territory is less optimistic than the national outlook. For a period of several decades, the St. Louis metropolitan area and surrounding parts of eastern Missouri have seen negative net migration. Simply put, more people have moved away from the area than those relocating to the area to take their place. This has caused the population to grow more slowly than many other major cities and the country as a whole. To be clear, the St. Louis area is experiencing population growth generally, but at a slow pace relative to other parts of the country. While St. Louis does have a diverse economy with some industries that export goods to other regions, the majority of economic activity is local in nature. Population growth slower than the national average generally goes hand-in-hand with slower economic growth. Based on these long-term demographic trends, we expect the Ameren Missouri service territory to grow at around half the pace of the U.S. economy. We also expect long-term general inflation to approximate 2%.

The development of regulations that can impact a utility's resource planning have continued to evolve in recent years. These regulations include current EPA regulations regarding emissions primarily from our fossil fueled power plants, regulatory requirements at our Callaway nuclear facility, and an evolving landscape of renewable energy standards currently at the state level along with energy efficiency policies and incentives. At the same time, methods for providing cost recovery and incentives associated with such regulations have been considered, and continue to be considered, by utility regulators in the various states. This confluence of regulatory currents intersects at the point of integrated resource planning, and the changing nature of the regulatory environment embodies one of the most important considerations when making long-term resource decisions. A complete assessment of current and future environmental regulations and mitigation is presented in Chapter 5. Considerations with respect to cost recovery treatment are included in our discussion of resource strategy selection, in Chapter 10.

2.2 Financial Markets[1]

In December 2008, in response to the financial downturn and continuing recession, the Federal Reserve (the Fed) lowered the short-term federal funds rate to a range of 0% to 0.25%. Since that time, the Fed has kept short-term interest rates at that historically low level and engaged in several rounds of monetary economic stimulus referred to as quantitative easing. With quantitative easing the Fed is making large-scale purchases of Treasury securities and mortgage-backed securities. Current expectations are for an end to quantitative easing in late 2014 and for interest rates to begin to rise in 2015. As economic conditions continue to improve and unemployment continues to drop, interest rates are expected to rise to historically average levels over a period of several years.

For this IRP, long-range interest rate assumptions are based on the December 1, 2013, semi-annual Blue Chip Financial Forecast. This forecast is a consensus survey of 49 economists from numerous firms including banks, investment firms, universities and economic advisors. Table 2.1 shows the analyst expectations for the yield on 10-year Treasury notes annually for 2015-2019 and a five-year average estimate for 2020-2024.

Table 2.1 Forecast Yield: 10-year Treasury Notes **NP**

[redacted]

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Long-term allowed return on equity (ROE) expectations for Ameren Missouri were developed using the projected long-term risk-free interest rate identified for 2020-2024 in Table 2.1. Ameren Missouri's equity risk premium was calculated by comparing the allowed ROE from Ameren Missouri's most recently completed rate case to the December 2012 10-year Treasury interest rate and adjusting for future interest rate expectations. Using this approach, the resulting expected value allowed ROE is 11.4% (see Table 2.2).

Table 2.2 Projected Allowed ROE **NP**

[redacted] **

[1] 4 CSR 240-22.060(2)(B); 4 CSR 240-22.060(7)(C)1A

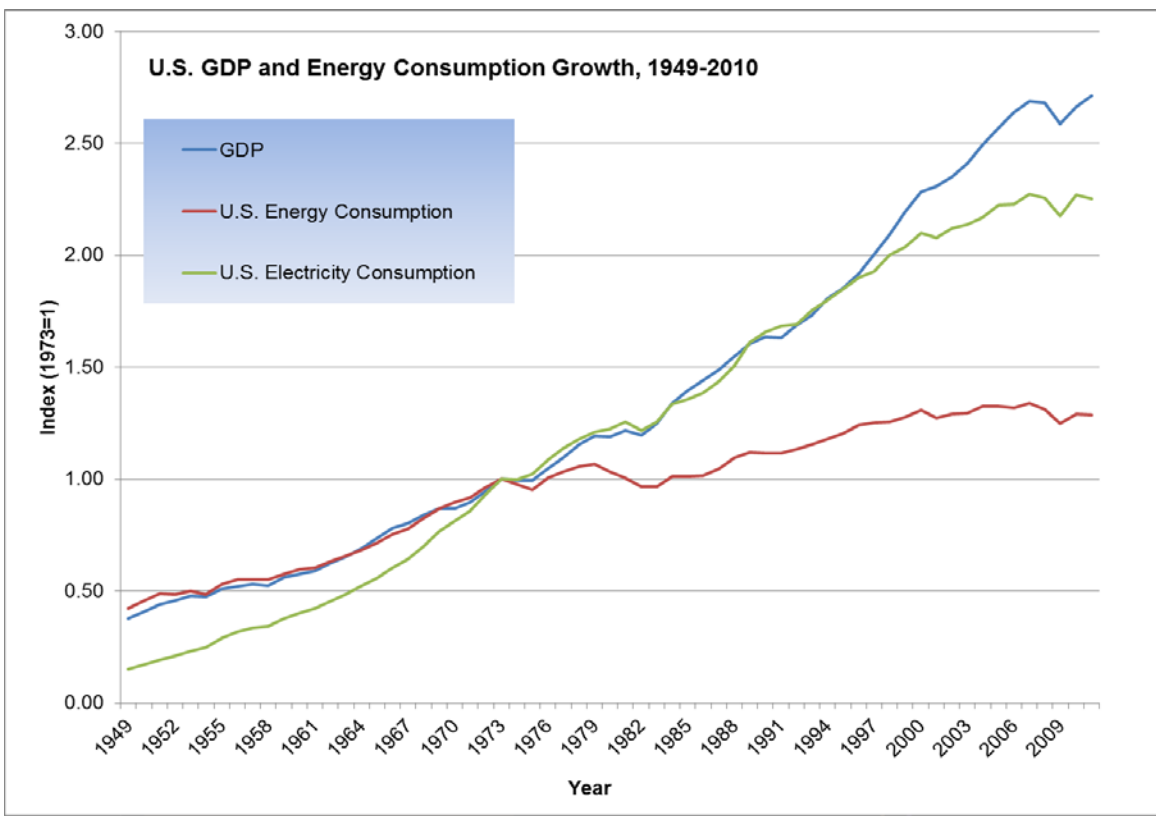
Because planning decisions are made in the present, Ameren Missouri uses its current weighted average cost of capital as the discount rate for evaluating present value revenue requirements and cash flows. Based on Ameren Missouri's most recently completed general rate case, our assumed discount rate is 6.46%. This is based on a capital structure that is 48.5% debt, 51.5% equity, and an allowed ROE of 9.8%.

2.3 Load Growth[2]

Load growth is typically a key driver of the market price of wholesale electric energy. The largest factor likely to affect load growth is the expected range of economic conditions that drive growth for the national economy and the energy intensity of that future economic growth. Historical trends in the energy intensity of the U.S. economy were studied to establish baseline trends.

That study revealed that the U.S. economy has exhibited long term trends toward decreasing energy intensity (i.e., less energy input required per unit of economic output). Figure 2.1 illustrates this point.

Figure 2.1 Energy Intensity Trends



[2] 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(A); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

The chart shows several decades of U.S. GDP, total U.S. energy consumption, and total U.S. electricity consumption, all indexed so that they take on a value of 1 in the year 1973. When you overlay these three data series on the graph, there are some interesting and clear takeaways that are apparent regarding trends in national energy intensity. From 1949-1973 total energy consumption in the U.S. grew almost 1:1 with economic output, as illustrated by the correlation of the red and blue index lines during those years. This period was characterized by significant growth the nation's manufacturing base, as well as widespread adoption of energy intense transportation and home appliances.

Around 1973, there was a clear change in the pattern, as total energy consumption grew markedly slower than economic output. This was around the time of the first oil embargo and energy price shocks that heightened the focus of the country on energy efficiency. The changes ushered in by those events clearly impacted total energy consumption, but as is apparent from the graph, total electricity consumption (a subset of total energy consumption (represented by the green line) continued to grow in virtual lock step with economic output (the blue line) until about 1990. This period of time saw expanded electrification of industrial processes as capital replaced labor at a high rate, increasing the electrical intensity of the economy. Additionally, air conditioning and other home conveniences were experiencing rapid growth in saturation rates at this time, supporting electric load growth.

From 1990 forward, the same trends that appeared in total energy consumption much earlier appeared in the electricity consumption. The growth of many home and business end uses began to slow as higher levels of saturation of air conditioning and other conveniences were realized. Additionally, federal standards led to improvements in the efficiency of many end use electrical appliances, such as the first refrigerator efficiency standards that date to this era. Finally, the most energy intensive regions of the manufacturing base of the nation began a long period of decline as many industries moved overseas in an effort to achieve lower labor costs.

It is apparent from this macro analysis of trends that the U.S. economy has, for decades, made strides in reducing the energy intensity of economic output, or said another way, become more energy efficient. With that backdrop, our expectation is that that overarching trend will continue. With that said, in order to assess the potential magnitude of future declines in energy intensity the key factors that drive energy intensity are considered independently. Those factors include expectations for trends in manufacturing, as manufacturing economic output is generally about three times as energy intensive as non-manufacturing activity. The recent boom in production of natural gas using horizontal drilling and hydraulic fracturing technology has the potential to cause resurgence in domestic manufacturing, particularly in the chemicals industry for which gas is an important feedstock.

Additionally, trends in energy efficiency, both efficiency induced by utility programs and that realized through building codes, appliance standards, and "naturally occurring," or economically induced efficiency, were assessed. Many states have established Energy Efficiency Resource Standards that will serve to promote adoption of end use technologies that use less energy to perform the same function as previous technologies. The goal of increasing the energy efficiency of end use appliances and equipment is also furthered by federal standards that require improving performance from many electrical applications.

Also, proliferation of customer-owned distributed generation, which appears as a reduction in demand for energy from utilities was studied as something that may have a meaningful impact over the planning horizon. While solar photovoltaic has seen rapid growth in some Southwestern U.S. markets with high solar irradiance, it has started to take on a more prominent role, spurred by various federal and state incentives, in other parts of the country, including in Missouri. While the future of solar equipment costs is uncertain in terms of the timing and magnitude, it is quite possible that the economics of solar will continue to improve over the planning horizon. Should this occur, there will likely be adoption of more systems that displace demand that would otherwise be planned for and served by utilities.

Considering the foregoing, our near term expectation is that load growth will be essentially flat through the 2016 time frame. After 2016, we have assumed a 0.6% average annual growth in load for the Eastern Interconnect across the 20 year planning horizon. A 0.6% rate of load growth would essentially equate to a continuation of the energy intensity trends that were observed for much of the last decade, applied to our base case assumptions regarding future economic growth.

To reflect the uncertainty for a higher growth case which may result from factors such as a more robust energy intense GDP driven by an increase in manufacturing, an annual average growth rate of 1.2% was assumed. 1.2% growth would result from an energy intensity trend similar to that observed in the 1990s and early 2000's applied to expected economic growth. Again, this would be most likely in the event that the secular decline in manufacturing reversed and we saw growth in chemical industries driven by shale gas or more heavy industries that return operation to the U.S. as overseas labor markets mature and increase in cost.

Finally, to reflect a low growth case in which a combination accelerating adoption of distributed generation and robust energy efficiency programs could easily provide an expectation for flat load, or 0.0% average growth rate across the planning horizon. While there is no historical precedent for a period with economic growth but no load growth, an acceleration of aggressive efficiency standards and programs coupled with rapid deployment of distributed technologies could offset the energy consumption driven by economic forces for a considerable period of time under the right circumstances.

2.4 Reliability Requirements

Ameren Missouri is a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity and energy markets. MISO has established a process to ensure resource adequacy through Module E of its FERC tariff. Module E establishes an annual resource adequacy construct which requires load-serving entities to demonstrate adequate resource capacity to satisfy expected load and reserve margins. MISO establishes its planning reserve margin (PRM) requirements annually through its loss of load expectation (LOLE) study process. MISO's last LOLE study report, published in late 2013, indicates a planning reserve margin requirement of 14.9% (applied to peak demand) in 2015, increasing to 17.3%. Table 2.3 shows the year-by-year PRM through 2023. Ameren Missouri has assumed that the PRM beyond 2023 remains at 17.3%.

Table 2.3 MISO System Planning Reserve Margins 2015 through 2023

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM $_{\text{Installed Capacity}}$	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for wind generation. The capacity credit is applied to the net output capability (in MW) of a wind farm to determine the amount of capacity that can be counted toward the PRM for resource adequacy. The MISO's value for wind capacity credit based on the 2013 Resource Adequacy report is 14.1%.

2.5 Energy Markets

Energy market conditions that may affect utility resource planning decisions include prices for natural gas, coal, nuclear fuel, and electric energy and capacity. Natural gas prices in particular have a strong influence on energy prices as on-peak wholesale prices are often set by gas-fired generators. Ameren Missouri has updated its assessment of these key energy market components to serve as a basis for analysis of resource options and plans.

2.5.1 Natural Gas Market[3]

Our assumptions for natural gas prices have been updated to reflect Ameren's "2014 Point of View Update". This update is a coordinated, corporate-wide view, developed by internal experts on natural gas markets. The Company's general expectations for the fundamentals affecting natural gas supply, demand and markets are largely unchanged from our most recent IRP annual update. Although there are significant changes occurring in supply, demand and infrastructure in the near term, natural gas is expected to be a reliable and economic fuel for the long term.

Natural Gas Price Drivers

Supply – The supply of natural gas continues to be robust with development of resources in the U.S. and in Canada. The shale gas plays have proven to hold greater reserves than initially estimated. The Potential Gas Committee[4] estimated that ultimately recoverable domestic potential reserves have grown from 2,241 trillion cubic feet (Tcf) in 2000 to 3,379 Tcf in 2010, to 3,914 Tcf in 2013. At current demand levels, natural gas reserves are sufficient to provide over 150 years of supply. Figure 2.2 shows the shale gas plays in North America.

Technology advancements continue to improve the productivity, energy efficiency and environmental performance of drilling sites. Natural gas production in the Lower 48 states has increased from 50 billion cubic feet (Bcf) per day in 2006 to 65 Bcf per day in 2013, an increase of nearly 30 percent. However, some state and federal regulators continue to challenge hydraulic fracturing ("fracking") technology through drilling moratoriums or stringent regulations.

[3] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B; EO-2014-0062 g

[4] The Potential Gas Committee, an incorporated, nonprofit organization, consists of knowledgeable and highly experienced volunteer members who work in the natural gas exploration, production and transportation industries and in the field and technical services and consulting sectors. The Committee also benefits from the input of respected technical advisors and various observers from federal and state government agencies, academia, and industry and research organizations in both the United States and Canada. Although the PGC functions independently, the Potential Gas Agency at the Colorado School of Mines provides the Committee with guidance, technical assistance, training and administrative support, and assists in member recruitment and outreach. The Potential Gas Agency receives financial support from prominent E&P and gas pipeline companies and distributors, as well as industry trade and research organizations and unaffiliated individuals.

Figure 2.2 North American Shale Gas Plays

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Demand - There are several drivers positively and negatively influencing demand. Advances in energy efficiency standards and promotion of energy efficiency programs have been effective in reducing residential and commercial heating demand. In contrast, relatively low natural gas prices have encouraged a resurgence of domestic petro chemical production and other industries reliant upon natural gas as a feedstock. Federal energy policy developments connected with clean energy standards and greenhouse gases (GHGs) are also expected to increase demand for natural gas-fired generation. In addition, the development of liquefied natural gas (LNG) facilities and Mexican exports are opening up higher priced global markets for domestic natural gas supplies.

Infrastructure – New pipeline and storage facilities will be required to provide market accessibility, reliability and integrity. Until recent years, the predominant flow of natural gas has been from the Midcontinent, Gulf Coast, Rockies and Texas regions across the

Midwest towards the Northeast. The developments in large gas production in the Marcellus and Utica shale reserves in the Northeast have created a dramatic shift in flow. Changes in the interstate pipeline system will occur as the supply pool for the Northeast grows and strands gas supplies. Natural gas will be directed toward the growing demand from: the petro-chemical industry in the Southeast, gas-fired generation throughout the Midwest, and East, and LNG exports in the Gulf Coast.

Price - Supplies of natural gas are expected to remain robust and will encourage the growth of industrial demand, gas-fired generation and global exports. Long-term, prices are expected to remain relatively low and stable. However, over the next ten years, regional price dislocations may occur as gas infrastructure struggles to keep pace with the changing gas supply and demand. For example, on January 24, 2014, daily spot prices for physical gas in the Northeast topped out at nearly $100/MMBtu while gas exiting the Marcellus (just 100 miles south) and Henry Hub remained below $6/MMBtu.

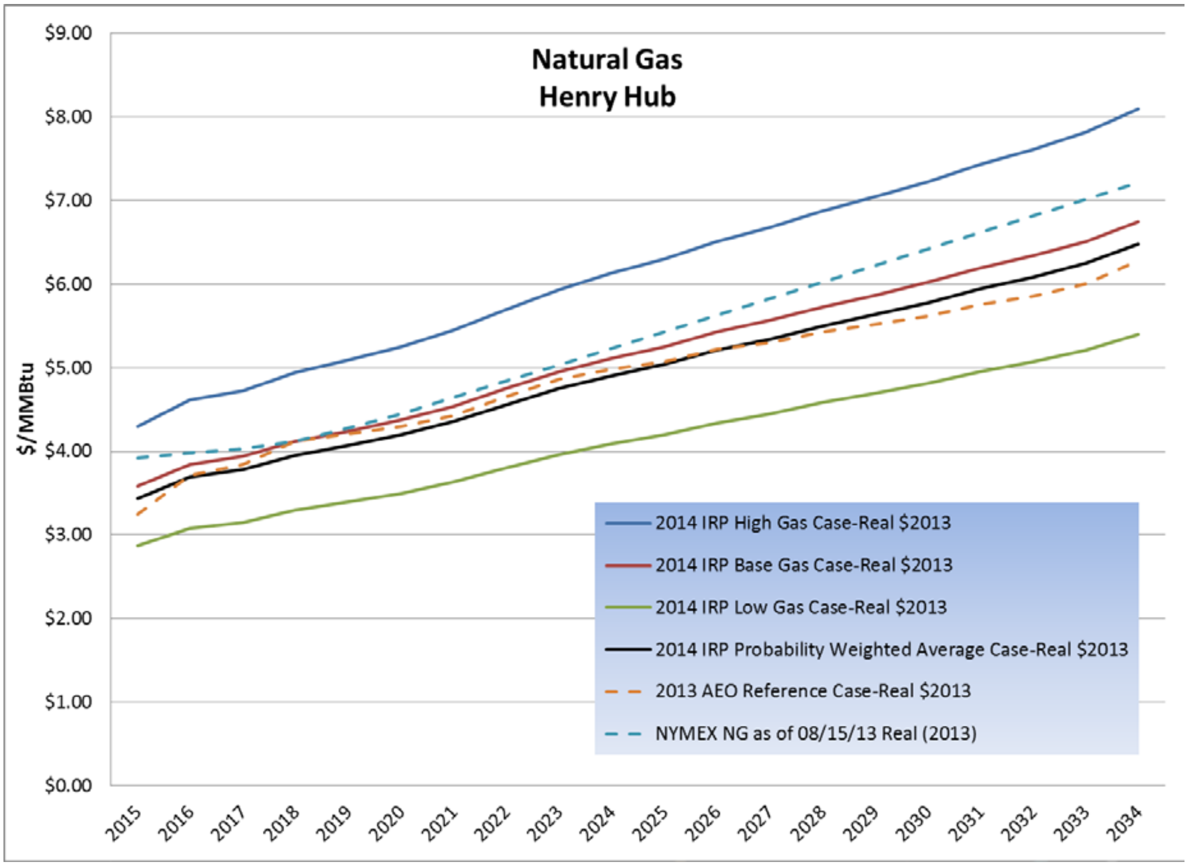
Natural Gas Price Assumptions

To develop our range of assumptions for natural gas prices, Ameren Missouri consulted its internal natural gas market experts. Several external expert sources of natural gas price projections have been reviewed in the development of our natural gas price assumptions. These sources include: Wood Mackenzie, Bentek, and the Nymex Henry Hub market prices. These research services, along with internal market knowledge of the natural gas industry, have helped to frame the long-term assumptions used and to provide context based on the drivers of the market. Based upon our assessment of the market fundamentals at this time and our long-term market expectations, the Company has developed assumptions for future prices for natural gas that are represented by the price levels shown in Table 2.4 and Figure 2.3.

Table 2.4 Natural Gas Price Assumptions

	Real Gas 2013 $									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High	$4.30	$4.61	$4.72	$4.94	$5.09	$5.25	$5.45	$5.70	$5.94	$6.13
Base	$3.58	$3.84	$3.94	$4.12	$4.24	$4.37	$4.54	$4.75	$4.95	$5.11
Low	$2.87	$3.08	$3.15	$3.30	$3.39	$3.50	$3.63	$3.80	$3.96	$4.08
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
High	$6.30	$6.51	$6.68	$6.87	$7.04	$7.22	$7.43	$7.61	$7.81	$8.10
Base	$5.25	$5.43	$5.56	$5.73	$5.87	$6.02	$6.19	$6.34	$6.51	$6.75
Low	$4.20	$4.34	$4.45	$4.58	$4.69	$4.82	$4.95	$5.07	$5.21	$5.40

Figure 2.3 Natural Gas Price Assumptions



2.5.2 Coal Market[5]

Our development of long term coal prices assumptions includes a review of the drivers that most affect the coal industry and long-term delivered coal. This process was centered on those drivers most directly affecting Powder River Basin coal (PRB) given that the vast majority of our current and expected coal supply will be sourced from this basin. Overall US coal supply is expected to shrink to 600-800 million tons per year over the next 20 years from the current rate of approximately 1 billion tons per year. However, PRB coal will gain a wider market share as the other US coal basins become uncompetitive (with the exception of the Illinois basin, which is expected to grow) due to increasing costs of mining resulting from geologic and regulatory changes.

[5] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B; EO-2014-0062 g

Coal Price Drivers

The long-term demand for PRB coal has been affected by declining natural gas prices and increasing natural gas supply along with declining production from eastern US coal fields, Central Appalachia and Northern Appalachia. PRB demand and pricing is also influenced by environmental regulations, transportation costs, and emission allowance markets. Export markets also impact PRB demand and will be driven by global economic strength, development of US export terminals on the west coast, and competing seaborne suppliers. US coal exports represent the swing supply into the global market and the PRB represents the available capacity to sell into the export market on upturns in demand.

Several factors will contribute to higher PRB production costs going forward including the following:

- Strip ratios (overburden vs. coal seam) are expected to increase
- Government regulations continue to increase reclamation costs
- Severance taxes and coal lease fees
- Cost of materials, supplies and capital equipment such as diesel fuel, explosives & haul trucks
- Haul distances from coal pit to load-out are expected to increase
- Eventual interference with the railroad mainline

As mining progresses from east to west in the PRB, the coal seams dive deeper such that strip ratios will increase by 25% or more over the next 20 years. The western progression also infringes upon the railroad mainline such that mines will be faced with the decision to either “leap over” the railroad and essentially start up a new mine or move the rail lines onto reclaimed property and continue the mining progression. This will affect the PRB mines on the “jointline” (served by both the BNSF and the UP railroads) at varying timeframes over the planning horizon. The exception is the Antelope Mine, which is already located to the west of the jointline.

Given our current plan to meet emission compliance for SO_2 standards is to burn ultra-low sulfur coal (considered 0.55 lb SO_2/MMBtu or less) our analysis explicitly assumes this in the development of market prices for delivered coal to the Ameren Missouri energy centers. Long term supply of ultra-low sulfur PRB coal is expected to be 200-350 million tons per year. Such supply range for this product will be driven by coal retirements over the planning horizon and a mix of scrubbed versus unscrubbed coal plants to balance the needs and supply for ultra-low sulfur coal.

Coal Price Assumptions

In the development of the coal price forecasts for use in the 2014 IRP the Ameren Missouri fuels team shaped low, base and high long-range forecasts for PRB coal delivered to our existing coal plants. This process included an assessment of current coal contracts (FOB at the mine) and rail contracts for delivery to each of our four coal plants. Next, a review of coal price projections from several outside services including Ventyx, Wood Mackenzie, Energy Ventures Analysis Inc. (EVA), US Energy Information Administration (EIA) and SNL were analyzed along with market-based forward curves. The coal price forecasts for low, base and high coal prices are shown in Table 2.5

Table 2.5 Delivered Coal Prices **NP**

[redacted]

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2.5.3 Nuclear Fuel Market[6]

Nuclear Fuel Price Drivers

Ameren Missouri relied on UxC for forecast of nuclear fule forecasts as we have for prior IRP analysis. Uxc provided annual price forecasts through 2025 for uranium (U3O8), conversion (UF6), and enrichment (SWU), front-end fuel components. It used

[6] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

the same approaches with each of the components. However, UxC forecasted spot prices for uranium and conversion, while it forecasted base prices for a new term contract for enrichment. The UxC price forecasts are generated by considering both market fundamentals (supply and demand) as well as an examination of short-term market behavior on the part of speculators and others that can exacerbate price trends set in motion by underlying supply and demand.

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

As it has before, UxC continues to focus on the demand for production, which takes total requirements and nets out secondary supplies such as Highly Enriched Uranium (HEU) feed to derive the underlying need for production. UxC also focuses on the expected balance of supply and demand in the spot market, since we are forecasting a spot price for uranium and conversion. Here, the role of speculators and financial interests become more important as they can represent additional demand. Financial interests may accumulate inventories, thus adding supply to the spot market.

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

Nuclear Fuel Price Assumptions

Ameren Missouri uses the nuclear fuel cycle component price forecasts of the Ux Consulting Company (UxC). UxC was used in this role in the 2008 and 2011 IRP, and the 2012 IRP update. The Westinghouse nuclear fuel cost model was used in calculating the small modular reactor (SMR) nuclear fuel cost forecast and the Surfnonline model by HTH Associates is used by Ameren Missouri for Callaway 1 and is also used with modified engineering specifications for the fuel type associated with the AP1000 nuclear power unit. Figure 2.4 shows the low, base and high nuclear price forecasts for a new nuclear unit.

Figure 2.4 Nuclear Fuel Price ForecastsNP****

[redacted]**

Each scenario is then assigned an individual probability basis that is related to the likelihood of the associated assumptions. The probability weighting is assigned on a year-by-year basis for uranium, while a single probability weighting is assigned for all years for conversion and enrichment.

2.5.4 Electric Energy Market

Ameren Missouri is a market participant within the MISO markets. We purchase energy and ancillary services to serve our entire load from the MISO market and separately sell all of our generation output and certain ancillary services into the MISO market. The vast majority of load and generation is settled in the day ahead market. Only those deviations from the day ahead awards are cleared in the real time market. MISO also operates a capacity market, and while clearing for capacity does impose certain obligations upon capacity resources (e.g. generators) including a must-offer obligation, the sale (or purchase) of capacity in the MISO market does not convey any rights or obligation to energy from the associated resource.

In actual market operation, each individual generator and the aggregate load receives a unique price for each hour in both the day ahead and the real time markets. The model, however, uses the same price for generation and load, given that Ameren Missouri receives an allocation of auction-revenue rights from the MISO based on its historical use of the system, which has generally proven to be sufficient to mitigate the price congestion between Ameren Missouri's base load generation and its load.

To develop power price assumptions for the planning horizon and to account for price uncertainty and the interrelationships of key power market price drivers, Ameren Missouri has used a scenario modeling approach as described in section 2.7.

2.5.5 Power Capacity Market

The capacity price forecast used in the 2014 IRP is based on a fundamental supply-demand relationship developed by MISO. Ameren Missouri is a member of MISO and actively participates in the MISO capacity markets. As mentioned previously, MISO publishes a report annually, its LOLE study report, for which analysis is performed to develop MISO's expectation for capacity planning reserves. This study provides a framework that includes the amount of installed generation capacity, peak load demand and transfers used to meet the reserve requirements as determined by a loss of load expectation study. The models used in this analysis include power flows within the MISO system and an expectation for transfers into and out of the MISO market.

This analysis was performed for three future years by MISO to determine how reserves will change over time; they include planning years 2014-2015, 2018-2019 and 2023-2024. The results of these studies as shown in the MISO LOLE report were used to determine when the MISO system would need additional capacity to meet reserve requirements. The results of this MISO study were adjusted to align with Ameren Missouri's expected coal plant retirement outlook developed for the IRP, discussed later in this chapter.

Additionally, our capacity price framework is based on the published value by MISO each year for the cost of new entry (CONE), which is based on the levelized cost of a new simple cycle gas-fired combustion turbine generator. Our assumption for capacity prices reflects the expectation that the market value of capacity will reach CONE when the MISO market is expected to become capacity constrained and additional capacity is needed to meet reserve requirements. This approach results in an expectation that the MISO market will become capacity constrained in 2021. Using a market-based price for the first several years and transitioning to CONE by 2021 results in assumed forward prices for capacity as shown in Figure 2.5. These capacity price assumptions were used as the basis for avoided capacity costs used to assess the cost-effectiveness of demand-side measures, discussed in Chapter 8. It was also used to assess the costs and revenues associated with capacity transactions modeled in the analysis of alternative resource plans, discussed in Chapter 9.

Figure 2.5 Capacity Price Assumptions **NP**

[redacted]

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2.5.6 Renewable Energy Standard

One of the considerations in developing alternative resource plans for Ameren Missouri is the need to comply with the Missouri Renewable Energy Standard (RES), which was passed into law by a voter initiative in November 2008. This standard requires all invester owned regulated Missouri utilities to supply an increasing level of energy from renewable energy resources or acquire the equivalent renewable energy credits (REC's) while subject to a rate impact limitation of 1% as determined by rules set by the Missouri Public Service Commission. The target levels of renewable energy, determined by applying increasing percentage to total retail sales, are:

- 2% in 2011-2013
- 5% in 2014-2017
- 10% in 2018-2020
- 15% starting in 2021

Additionally, a solar carve-out provision is included in the standard and requires that at least 2% of renewable energy be sourced from solar generation. This provision can also be met with the purchase of solar REC's or SREC's. Our analysis of RES compliance is presented in Chapter 9.

2.6 Environmental Regulation[7]

With increasingly stringent regulation of coal-fired power plants, including continuing efforts to regulate GHG emissions, the effects of these regulations on the electric energy market must be considered in assessing potential resource options and portfolios. More specifically, the environmental statutes and regulations include:

- Clean Air Act (CAA)
  - National Ambient Air Quality Standards (NAAQS)
    - Clean Air Interstate Rule (CAIR)
    - Cross State Air Pollution Rule (CSAPR)
  - Acid Rain Program
  - Prevention of Significant Deterioration (PSD)
    - Maximum Achievable Control Technology (MACT) for new sources
  - Section 111
    - Section 111(b) GHG New Source Performance standards for new, reconstructed and modified coal and gas fired power plants
    - Section 111(d) GHG New Source Performance standards for existing coal fired power plants
  - Mercury and Air Toxics Standards (MATS)
- Clean Water Act (CWA)
  - Section 316a regulations covering thermal discharges
  - Section 316b regulations covering water intake structures
  - Wetlands/Waters of the U.S.
  - Spill Prevention Control & Countermeasures (SPCC)
  - Effluent Limitations Guidelines Revisions (ELGs)
- Safe Drinking Water Act
- Solid Waste Disposal Act
  - Coal Combustion Residuals (CCR)
- Resource Conservation and Recovery Act (RCRA)
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)
- Superfund Amendments Reauthorization Act (SARA)
- Toxic Substances Control Act (TSCA)
  - PCB regulations
- Emergency Planning & Community Right-To-Know Act (EPCRA)

In addition to this list, the potential for new and more stringent laws and regulation create a changing landscape for investment decisions over the planning horizon. While

[7] EO-2014-0062 h

the effects of these current and potential future regulations are complex, a primary consideration is how they will affect power prices. Given this goal, our process established that changes in power markets would most significantly be impacted through the degree and timing of coal plant retirements across the entire Eastern Interconnect.

In addition to the existing and future regulations outlined above, we must also consider potential actions with respect to climate policy and regulation of GHG emissions beyond what was recently proposed by EPA in the form of its Clean Power Plan. To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined reports from several research and consulting companies, such as Wood Mackenzie, IHS Cera, and Synapse Energy Economics, Inc. We also reviewed US government reports on the so-called "social cost of carbon." Through this process we considered the structures a future GHG policy could be implemented which included the following;

- Legislative
- Regulatory
- International Treaty

We identified three general mechanisms by which GHG policy could be implemented through any of the above structures. Each implementation path could seek to achieve GHG reductions through any, or a combination of, three mechanisms:

- Policies to mandate and/or promote low/no carbon resources
- Specified limits on GHG emissions (emission rates or mass emission)
- Implementation of an explicit price on GHG emissions

This framework provided a vehicle for discussion with our internal experts to identify the probable ranges of coal retirements and carbon prices that define our scenarios. Through this process an updated set of assumptions was developed to reflect environmental policy effects on coal retirement expectations, as well as the timing, magnitude and probability of an explicit price on carbon dioxide emissions.

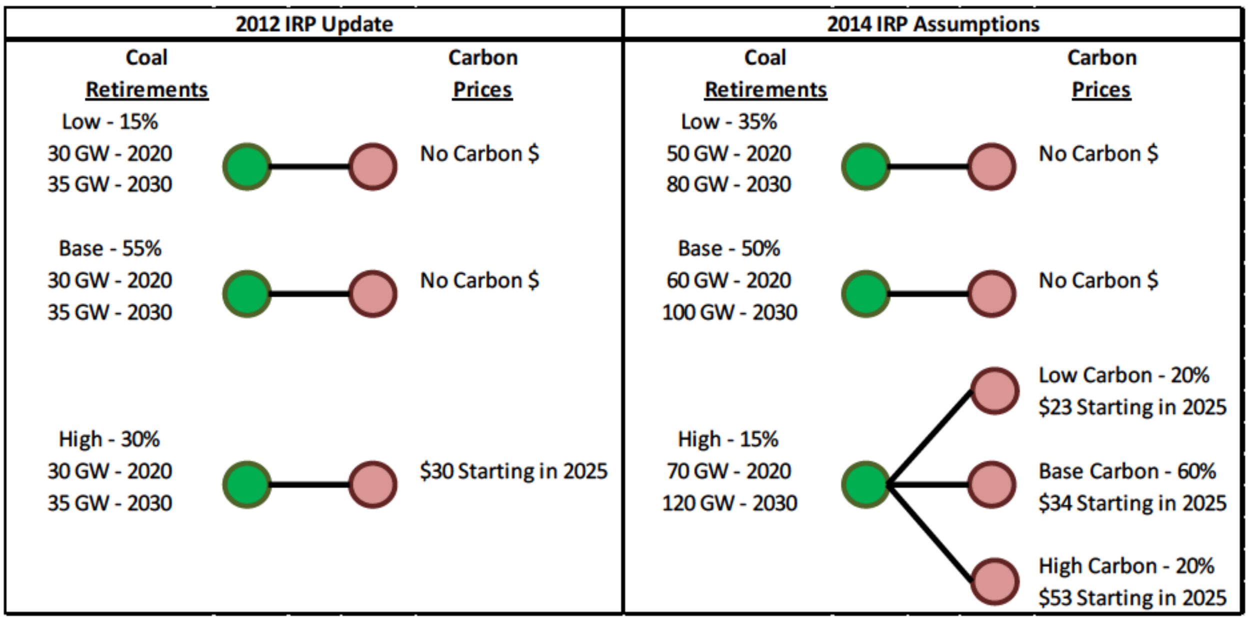
Coal Plant Retirements[8]

Our power price scenario model, described in section 2.7, relies on Ventyx' s national dataset. This dataset includes assumptions for expected coal plant retirements spanning the 20-year time frame of the IRP and was used as a starting reference. This dataset includes plant closures based on company announcements and Ventyx's analysis given current laws and regulation at the time of publishing the dataset used in

[8] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.060(5)(C)

the study. This set of retirements was reviewed in light of the current and expected regulations over the planning horizon. In order to reflect the range of possible environmental futures that represent the planning horizon, our previous coal plant retirements assumptions for three levels – low, base, and high – were updated based on review and multiple discussions with internal experts involved in environmental regulation and policy. Figure 2.6 shows the changes made for the 2014 IRP.

Figure 2.6 Coal Retirement Assumptions



Carbon Dioxide Emissions Prices[9]

In addition to coal plant retirements, an update to the carbon price expectation and the timing of this price was reviewed. To represent a range of prices for carbon dioxide emissions, we have relied on Synapse's November 1, 2013, Carbon Dioxide Price Forecast report. We have used the low, mid and high case prices from this report. However, only those values from 2025 and beyond are included in our analysis based on the expectations for carbon policy of our internal experts. The price of carbon dioxide emissions is assumed to be zero in all years prior to 2025. We have assumed a high level of coal plant retirements in conjunction with an explicit price on carbon dioxide emissions given the expectation that this carbon price will result in the most restrictive operations of coal facilities. Table 2.6 shows the values from Synapse used in the current IRP analysis. A symmetrical weighting was used to represent the probability of

[9] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(D); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(C); 4 CSR 240-22.060(5)(H); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B; EO-2014-0062 g

each of these cases with 60% weighting on the mid case and 20% each on the high and low cases.

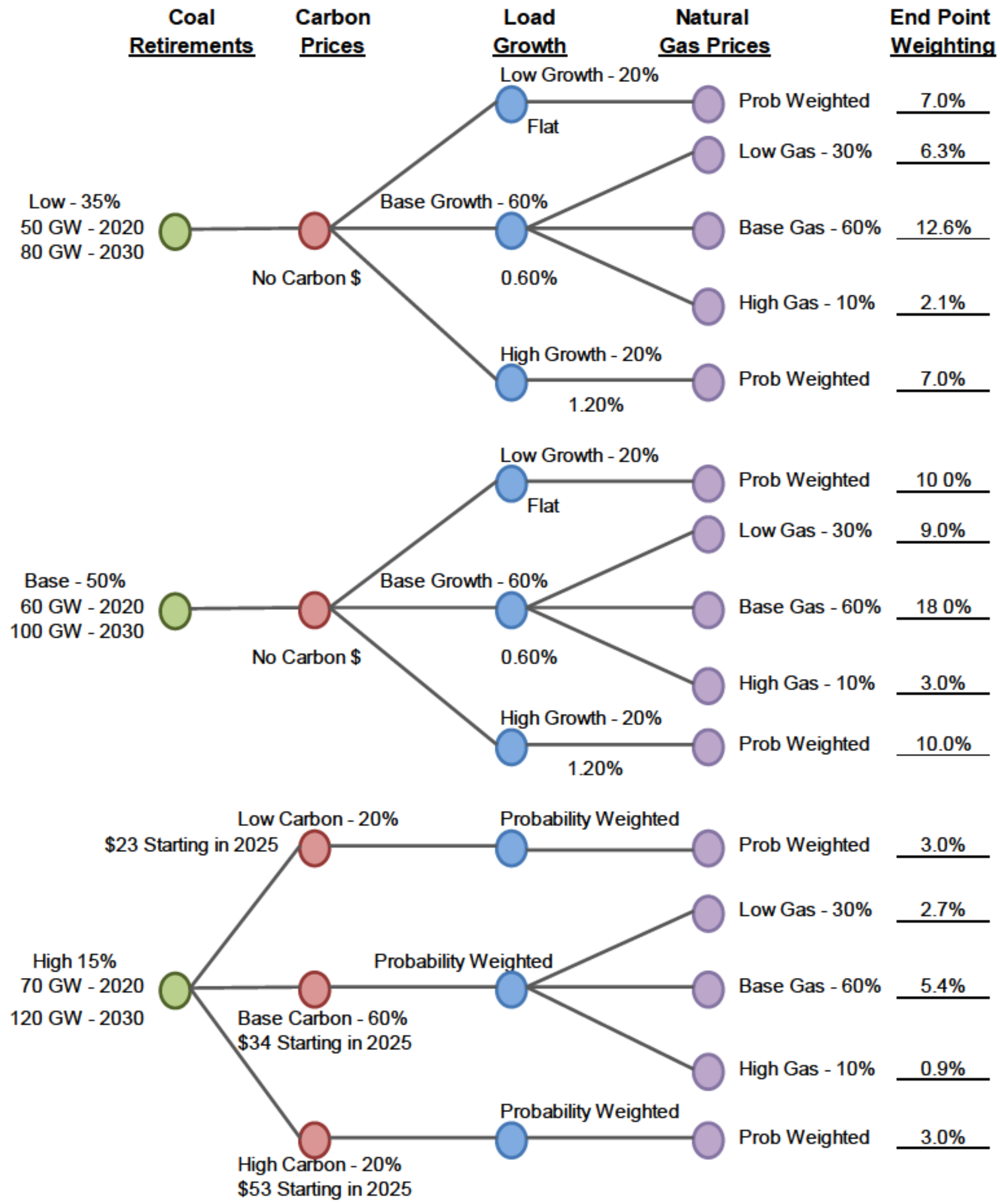
Table 2.6 Carbon Dioxide Emissions Price Assumptions

Synapse 2013 Report						
	2012 $/Ton Real			Nominal		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2025	$18	$26	$41	$23	$34	$53
2026	$19	$29	$45	$25	$38	$59
2027	$21	$31	$48	$28	$41	$64
2028	$22	$33	$51	$30	$45	$70
2029	$24	$35	$54	$33	$49	$76
2030	$25	$38	$58	$36	$54	$82
2031	$27	$40	$61	$39	$58	$89
2032	$28	$42	$64	$42	$62	$95
2033	$30	$44	$67	$45	$67	$102
2034	$31	$47	$71	$48	$72	$109
2035	$33	$49	$74	$51	$77	$116

2.7 Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation, and natural gas prices. Using our assumptions for load growth, coal retirements, carbon prices, and natural gas prices, we developed scenarios based on various combinations of these assumptions. The development of scenario modeling is best represented by a probability tree diagram and the associated probability of each branch of the tree. Each branch of the tree is used to represent a combination of dependent input variables that can have an impact on plan selection. In order to focus on those combinations with the greatest influence on alternative resource plan performance, potential branches that would be characterized by a significantly low probability of occurrence are collapsed to provide a simplified yet still robust set of possible branches. This process provides for a wide range of potential future combinations with which we can analyze alternative resource plan performance and risk. Figure 2.7 shows the final scenario tree.

Figure 2.7 Final Scenario Tree



Electric Power Prices[10]

To support our analysis of alternative resource plans, as described in Chapter 9, we developed forward price forecasts at the Indy Hub using modeling software provided by Ventyx and commonly referred to as “Strategic Planning” or “MIDAS”. This detailed simulation modeling software provides an economic dispatch production cost projection that utilizes load, fuel price, power production capabilities and many other assumptions

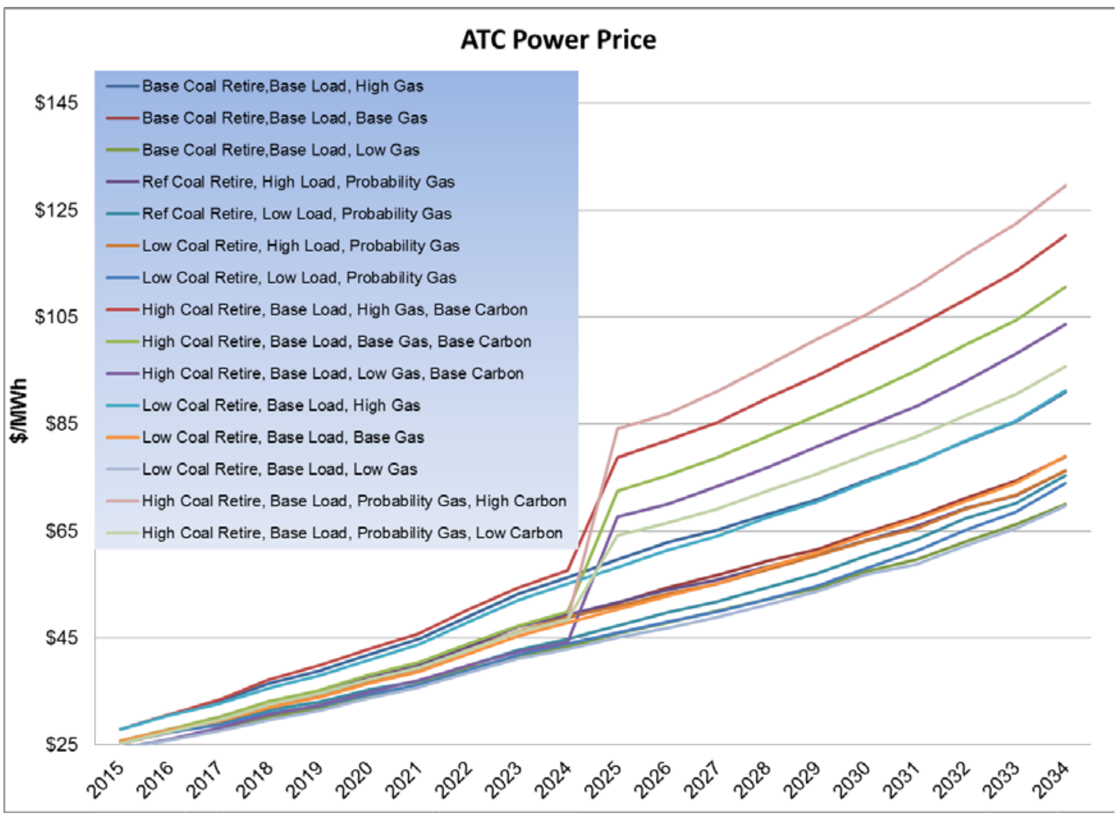
[10] 4 CSR 240-22.060(5)(G); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

and projections. To provide the detailed data needed to populate the Strategic Planning model for purposes of developing a forward electric price forecast, Ventyx provides a service that incorporates all the assumptions that are used in their Power Reference Case. The Ventyx Power Reference Case is an iterative integrated process used to determine the impacts that capacity additions and retirements have on power markets. This process also considers the renewable energy expansion necessary to meet state Renewable Portfolio Standard targets but no federal renewable standard. The Spring 2013 Reference Case incorporates CAIR and MATS emission assumptions along with Regional Greenhouse Gas Initiative compliance.

To ensure that a range of possible future power prices were incorporated, those inputs determined to be uncertain and impactful enough to warrant the need for a range of possible inputs were varied. These inputs were;

- Long-term assumptions for load growth
- Natural gas prices
- Coal plant retirements representing the impacts of environmental regulation
- An explicit price on carbon dioxide emissions in some cases

Figure 2.8 Scenario Power Prices



These inputs were varied in the model from the Ventyx reference case provided. This process produced values based on the probability tree shown in Figure 2.7. The results of this modeling for each branch yields different power price futures. Figure 2.8 shows those price curves corresponding to the scenarios described earlier in this section.

Power Price Shaping

It is necessary to convert the ATC Power Prices for the Indiana Hub (obtained in the manner explained above) into 8,760 hourly prices for each year by scenario in order to achieve reasonable results from the RTSim production cost model, which uses an hourly dispatch to model the system. For this IRP, Ameren Missouri has used the same methodology for shaping block prices into hourly prices as it uses in its fuel budgeting modeling.

Before such shaping can occur, the ATC Power Prices for the Indiana Hub must first be basis adjusted for time (real time to day ahead (DART)) and for location (INDY Hub to Ameren Missouri generation).

Once ATC prices have been basis adjusted they are broken down into monthly block prices for each year in each scenario utilizing historical ratios of individual months to the annual ATC price, and peak blocks (5x16, 2x16 and 7x8) within a month to that month's price. These block prices by month are then shaped into hourly prices utilizing the 2011 day ahead price curve applicable to Ameren Missouri's base load generators. 2011 was selected as the reference year to maintain consistency with use of the same year for load shaping.

These power prices were used in the analysis of alternative resource plans described in Chapter 9. They were also incorporated into unique forecasts of Ameren Missouri load for each scenario to account for price-demand elasticity, as described in Chapter 3.

2.8 Compliance References