2. Planning Environment

Highlights

- *General economic conditions suggest flat to negative growth, resulting in lower loads when combined with increasing energy efficiency.*
- *Natural gas prices continue to be driven by large domestic supplies of shale gas, and our assumptions span a range of $2.50 - $5 per MMBtu in today's dollars over the planning horizon.*
- *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 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 continued to improve in the U.S. over the last few years. Ameren Missouri's expectations are for 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 continues 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. While this trend has started to reverse very recently, the St. Louis area is expected to continue to experience population growth at a slow pace relative to other parts of the country. Because the majority of economic activity is local in nature, population growth that is 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]

An ambitious post-election economic agenda provides a robust backdrop for longer term economic growth expectations. The anticipated major tax cuts, increased defense spending, reduced regulations and infrastructure spending are all prospective long-term drivers for a stronger expanding economy. Much of this enthusiasm must be tempered in the back drop of the United States having a large debt to GDP ratio, low inflation and low unemployment. These headwinds will likely temper growth rates even in an accommodative environment for growth. This setting has provided the expectation for modestly stronger long term economic growth and inflation to be slightly higher than

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

previous expectations. Interest rates will likely normalize at a slightly faster pace and the new normal neutral federal funds rate could be marginally higher

For this IRP, long-range interest rate assumptions are based on the December 1, 2016, 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 2018-2022 and a five-year average estimate for 2023-2027.

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

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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 2023-2027 in Table 2.1. Ameren Missouri's forward equity risk premium was calculated by applying a linear fit calculated relationship between historical electrical authorized ROE and 10 year treasury notes. This relationship provides an implied risk premium that can be determined based on an expected treasury rate. Using this approach, the resulting expected value of allowed ROE is 10.6% as shown in Table 2.2.

Table 2.2 Projected Allowed ROE **

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The assumed range of interest rates for the 2017 IRP are calculated from an average of Blue Chip Financial Long Range forecasts for Corporate Aaa and Corporate Baa bond yields for the 2023-2027 timeframe. The base Consensus forecast became our base assumption and the top ten analyst average our high case and the lower 10 analyst average our low case, roughly corresponding to the top 20% and bottom 20% of the range, respectively.

Table 2.3 Interest Rates **

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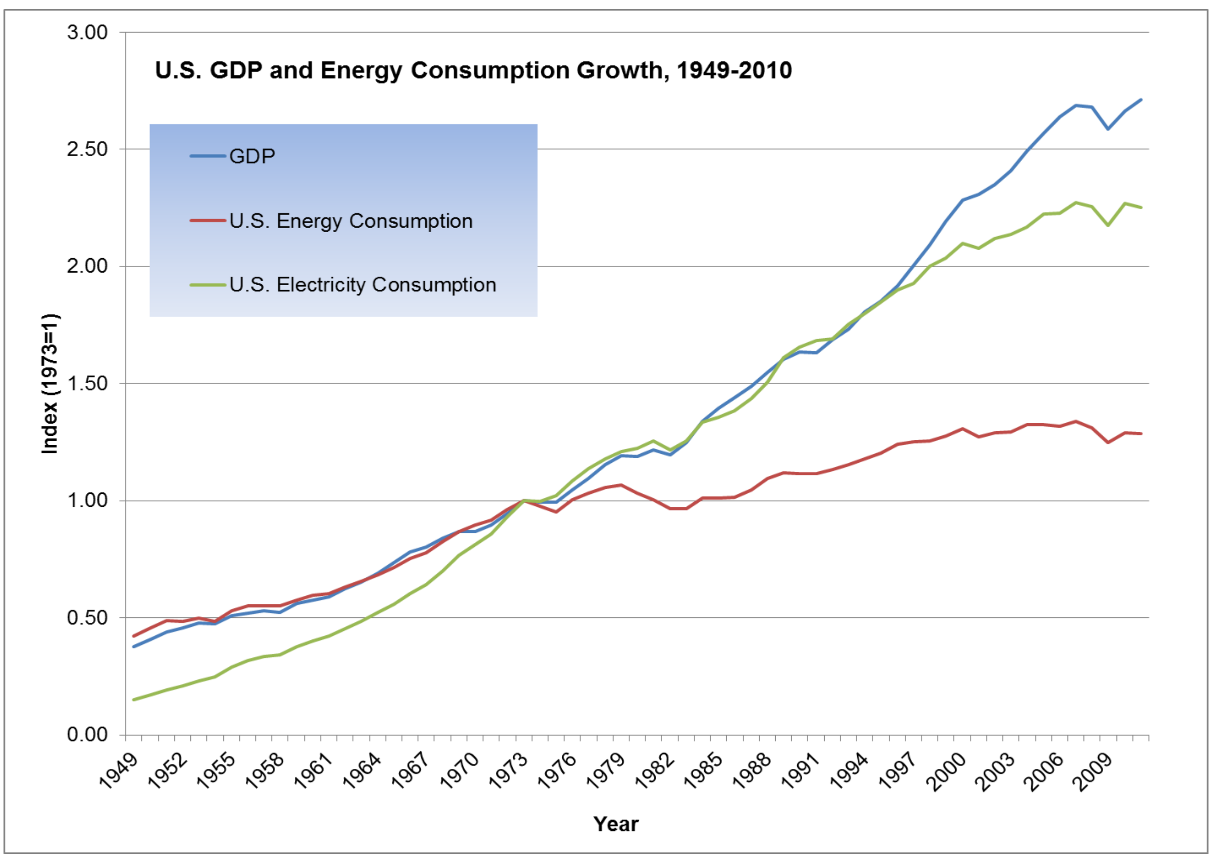
Because planning decisions are made in the present, Ameren Missouri uses its current weighted average cost of capital as the discount rate for evaluating present value revenue requirements and cash flows. Based on Ameren Missouri's most recently completed general rate case, our assumed discount rate is 5.95%. This is based on a capital structure that is 48.2% debt, 51.8% equity, and an allowed ROE of 9.53%.

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 in 2014 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 in 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 probable that the economics of solar will continue to improve over the planning horizon.

Considering the foregoing, our near term expectation is that load growth will be essentially flat through the 2017 time frame. After 2017, we have assumed a negative 0.37% average annual growth in load for the Eastern Interconnect across the 20 year planning horizon. A negative 0.37% rate of load growth would essentially equate to an acceleration of the reduction in 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 and the potential for greater penetration of electric vehicles, an annual average growth rate of 0.48% was assumed. 0.48% growth would result from an energy intensity trend similar to that observed in the 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 of accelerating adoption of distributed generation and robust energy efficiency programs could easily provide an expectation for a negative 1.36% average growth rate across the planning horizon. While there is no historical precedent for a period with economic growth and negative load growth, an acceleration of aggressive efficiency standards and programs coupled with rapid deployment of distributed energy 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 remains a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity, energy and ancillary services 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 2016, indicates a planning reserve margin requirement of 15.6% (applied to peak demand) in 2017. Table 2.4 shows the year-by-year PRM requirement through 2026. Ameren Missouri has assumed that the PRM beyond 2026 remains at 15.7%.

Table 2.4 MISO System Planning Reserve Margins 2018 through 2026

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026
PRM Installed Capacity	15.6%	15.3%	15.4%	15.5%	15.5%	15.6%	15.6%	15.7%	15.7%

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 2017 Resource Adequacy report is 15.6%.

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 continue to 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.

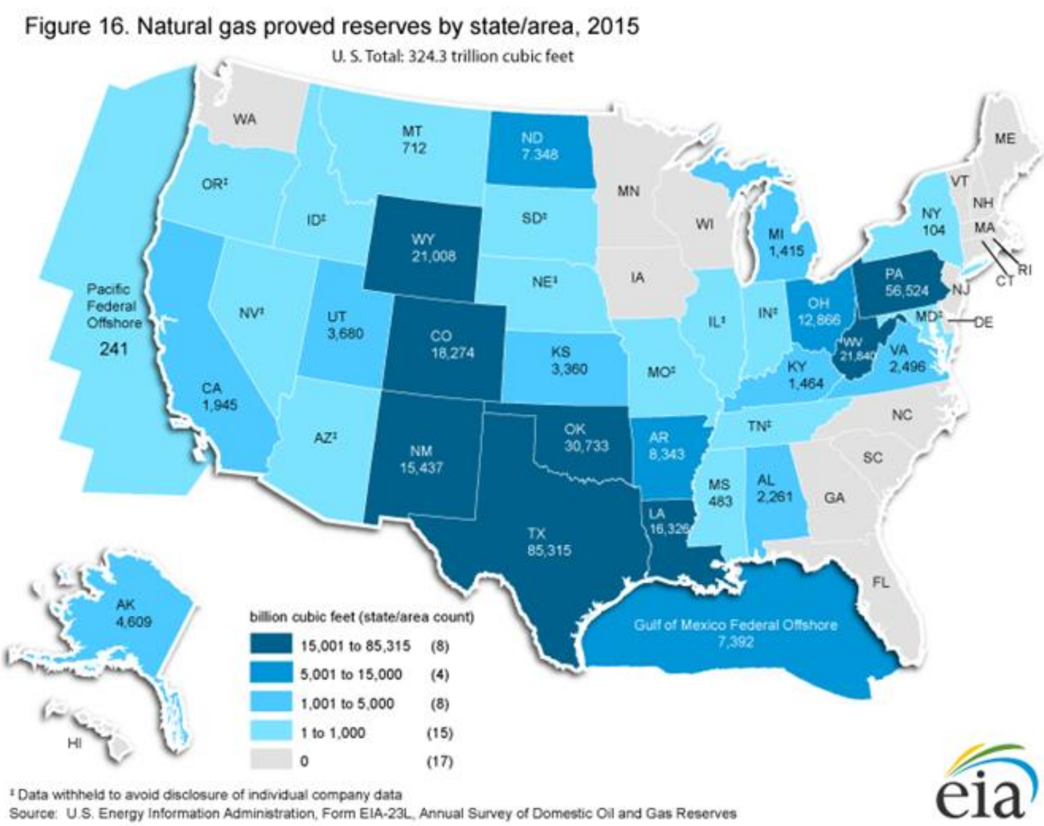
2.5.1 Natural Gas Market[3]

Our updated assumptions for natural gas prices reflect Ameren Missouri's most current expectations developed by internal subject matter 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. The natural gas industry has experienced significant improvements in production efficiency capability and pipeline infrastructure investment. Natural gas supplies are projected to be abundant, reliable and an 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 Energy Information Agency (EIA), shows in Figure 2.2 that natural gas production has grown nearly 4% per year since 2005 and is expected to continue to grow at that rate until 2020.

Figure 2.2 North American Natural Gas Reserves



[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

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 74 Bcf per day in 2015, an increase of nearly 50 percent. However, some state and federal regulators continue to challenge hydraulic fracturing (fracking) technology through drilling moratoriums or stringent regulations. Recent low prices have begun to dampen production in regions where production costs are marginally profitable. The current relatively low price environment has resulted in a large number of wells that have been drilled but are uncompleted. Production is expected to increase as new demand pushes prices to more profitable ranges for most production areas.

Demand – Natural gas consumption remains relatively unchanged for the residential and commercial markets as energy efficiency improvements offset modest housing starts and new commercial space. The favorable characteristics of natural gas; relatively clean emissions, low current and expected prices, reliable and abundant supplies make it an attractive fuel to support industrial growth and electric generation. The combination of low prices for natural gas and federal energy policy developments connected with clean energy standards and greenhouse gases (GHG) are expected to increase demand for natural gas-fired generation. These factors have encouraged a resurgence of domestic petro-chemical production and other industries reliant upon natural gas as a feedstock. 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. 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.

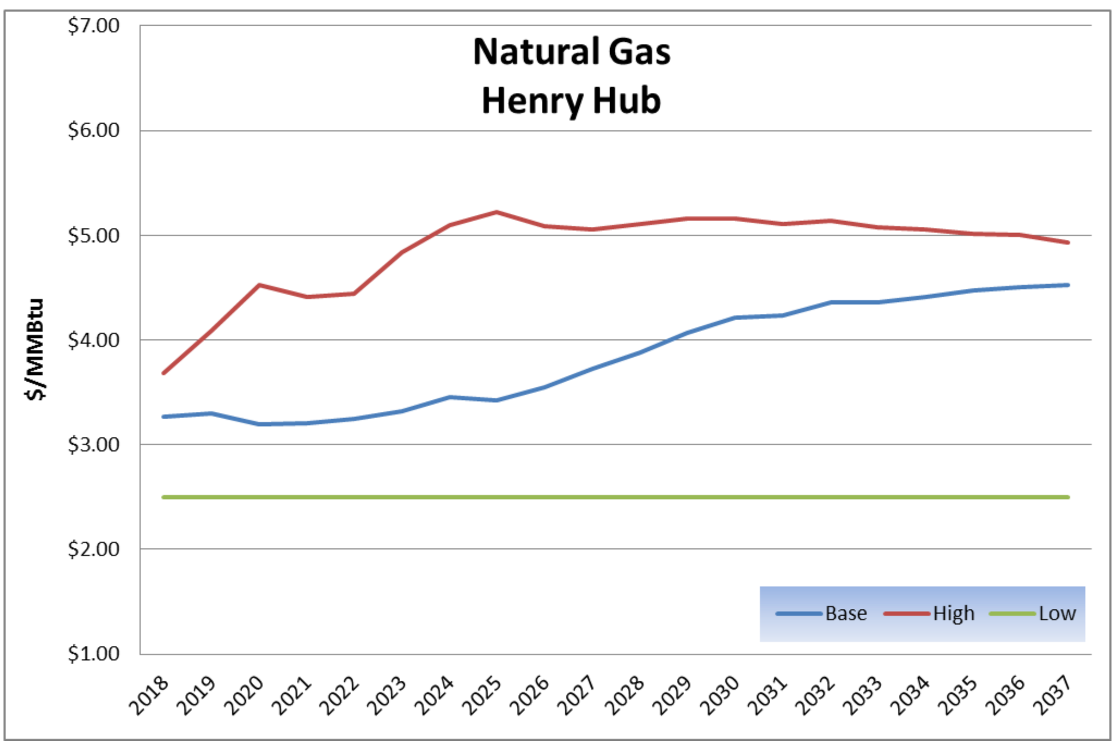
Natural Gas Price Assumptions

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, PIRA, BTU Analytics, EIA , 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 2.5 and Figure 2.3.

Table 2.5 Natural Gas Price Assumptions

Real Gas 2016 $										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
High	$3.69	$4.09	$4.52	$4.41	$4.44	$4.84	$5.10	$5.23	$5.09	$5.05
Base	$3.27	$3.30	$3.20	$3.21	$3.25	$3.32	$3.46	$3.42	$3.55	$3.72
Low	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
High	$5.10	$5.15	$5.16	$5.11	$5.14	$5.08	$5.05	$5.01	$5.00	$4.93
Base	$3.89	$4.07	$4.21	$4.24	$4.35	$4.36	$4.41	$4.48	$4.50	$4.53
Low	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50

Figure 2.3 Natural Gas Price Assumptions



2.5.2 Coal Market[4]

Our development of long term coal price assumptions includes a review of the main drivers that most affect coal production and consumption for electric generation. This process was centered on those drivers most directly affecting Powder River Basin (PRB) coal given that the vast majority of our current and expected coal supply will be sourced from this basin. Overall U.S. coal supply is expected to be in the range of 700-850 million tons per year over the next 20 years. This is down from the recent past of one billion tons but is comparable to the 2016 volume of approximately 800 million tons. However, it is anticipated that PRB and Illinois Basin coals will gain a slightly wider market share as the other, less economical, US coal basins contract due to competition with energy sources like natural gas and renewables.

Coal Price Drivers

The long-term demand for PRB coal has been affected by low natural gas prices and increasing natural gas supply along with declining production from eastern U.S. coal fields, Central Appalachia and Northern Appalachia. PRB demand and pricing continues to be influenced by environmental regulations, transportation costs, and emission allowance markets. Export markets could also impact PRB demand in the future. Potential increases in exports of Appalachian and Illinois Basin coals will be driven by global economic strength and competition from other seaborne suppliers. U.S. coal exports represent the swing supply into the global market. Increased U.S. coal demand created by exporting domestic coal would likely be backfilled by PRB and other Illinois Basin coals.

PRB coal prices and production may vary as a result of any potential actions taken by the U.S. President and appointed officials during the next four years. This could include; changes in natural gas fracturing/production, halting or weakening open environmental rules, phasing out subsidies for renewable energy, changes in coal plant retirement schedules and reducing federal severance, royalties and tax rates on coal leases. An example of this kind of policy change includes the current administration's decision to drop out of the Paris Climate Agreement.

Several factors will contribute to volatile and likely 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 including coal producers potentially having to insure payment of future reclamation costs ("self-insurance" may be more limited in the future)

[4] 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

- Severance taxes and coal lease fees (moratorium on federal coal leases as of 2016)
- 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 "Joint Line" (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 Joint Line.

Coal prices may vary from the forecast due to the drivers mentioned above but are not limited to those drivers alone. Examples of other drivers that may impact coal prices are new mining, generation or environmental technology, changes in the electric grid and load loss/growth.

Given our current plan to meet emission compliance for SO_2 standards is to utilize installed environmental controls and burn predominately ultra-low sulfur coal (typically 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 2017 IRP the Ameren Missouri fuels team shaped low, base and high long-range forecasts for PRB coal delivered to our existing coal-fueled Energy Centers. This process included an assessment of current and future expectations of PRB coal prices (FOB at the mine) rail transportation contracts (including diesel fuel surcharges) for delivery to each of our coal-fueled Energy Centers. Next, coal price projections from several outside services including Ventyx, PIRA, Wood Mackenzie, Energy Ventures Analysis Inc., US Energy Information Administration (EIA) and SNL were analyzed along with market-based forward curves to produce PRB low, base and high forecasts. The coal price forecasts for low, base and high coal prices are shown in Table 2.6

Table 2.6 Delivered Coal Prices ($/Ton) **

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2.5.3 Nuclear Fuel Market[5]

Nuclear Fuel Price Drivers

Ameren Missouri relied on UxC for nuclear fuel forecasts as we have for prior IRP analyses. Uxc provided annual price forecasts through 2030 for uranium (U3O8), conversion (UF6), and enrichment (SWU), front-end fuel components. It used the same approaches with each of the components. However, UxC forecasted spot prices for uranium, while it forecasted base prices for a new term contract for conversion and 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

[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

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 previously for the 2008, 2011, and 2014 IRPs. 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 Forecasts**

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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 continues to be 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.

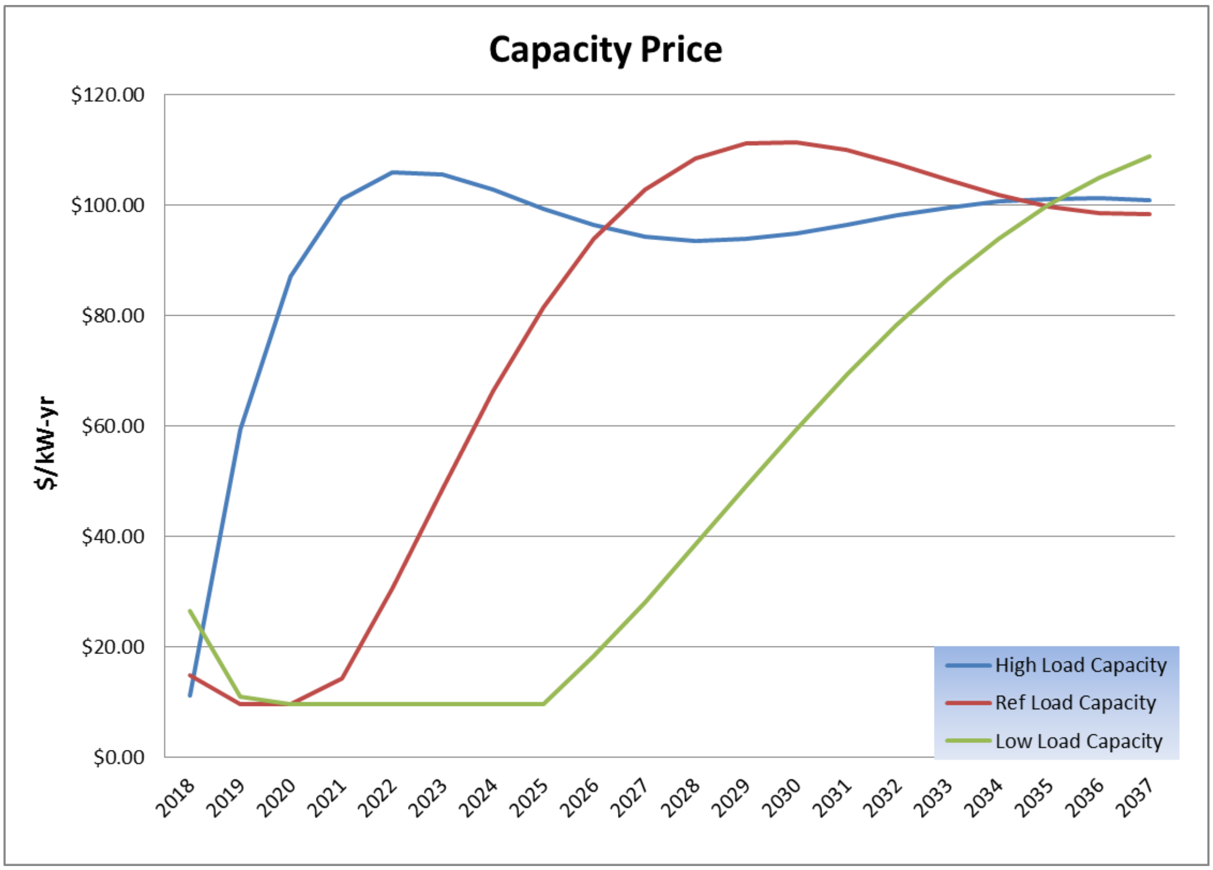
2.5.5 Power Capacity Market

The capacity price forecast used in the 2017 IRP is based on a fundamental supply-demand relationship developed by running 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 and projections. To provide the detailed data needed to populate the Strategic Planning model for purposes of developing a forward capacity 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.

This software has the ability to develop a value for capacity based on meeting reserve margins requirements as set by the ISO. The model determines if new capacity needs to be built to meet reserve margin requirements and will add generation to regions to meet that need. Once the new generation has been added to the region's resource mix the value of capacity is set at the full cost of the generation minus the energy revenue it receives from the market.

Figure 2.5 shows the capacity price curves produced by MIDAS and used for integration and risk analysis as discussed in Chapter 9. The three capacity price curves correspond to the base, high and low load growth scenarios discussed previously as load growth was found to be the primary driver of capacity prices.

Figure 2.5 Capacity Price Assumptions



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 (RECs) 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 RECs or SRECs. Our analysis of RES compliance is presented in Chapter 9.

2.6 Environmental Regulations

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)
    - Implementation of ambient standards for ozone, PM (particulate matter) and sulfur dioxideCross State Air Pollution Rule (CSAPR)
  - Maximum Achievable Control Technology (MACT) Standards
    - Mercury and Air Toxic Standards (MATS)
  - 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
  - New Source Review
  - Regional Haze
- 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)
        - Ash Pond Closure Initiatives
- 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
    - Implementation of the recent amendments to TSCA under the Frank T. Lautenberg Chemical Safety for the 21st Century Act
- Emergency Planning & Community Right-To-Know Act (EPCRA)

A more detailed discussion of enviromental regualtions can be found in Chapter 5. In addition to this list, the potential continues for new and evolving laws and regulation to create a changing landscape for investment decisions over the planning horizon. While the effects of these current and potential future regulations are complex, a primary consideration continues to be how they will affect power prices. 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 the regulation that was finalized by the EPA in the form of its Clean Power Plan (CPP). 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 IHS Cera, Synapse Energy Economics, Inc along with MISO studies of the CPP. We also reviewed the 2016 EIA reference case along with their alternative Clean Power Plan cases.

We identified three general paths forward by which GHG policy would be implemented through any of these paths;

- CPP struck down and carbon regulations become a state by state patchwork
- Carbon reduction goals move forward in a CPP form or some other structure that achieves similar carbon reductions
- A more restrictive carbon future that incorporates added renewables, energy efficency and increasing enviromental regulation pressures provide for a more carbon limited case

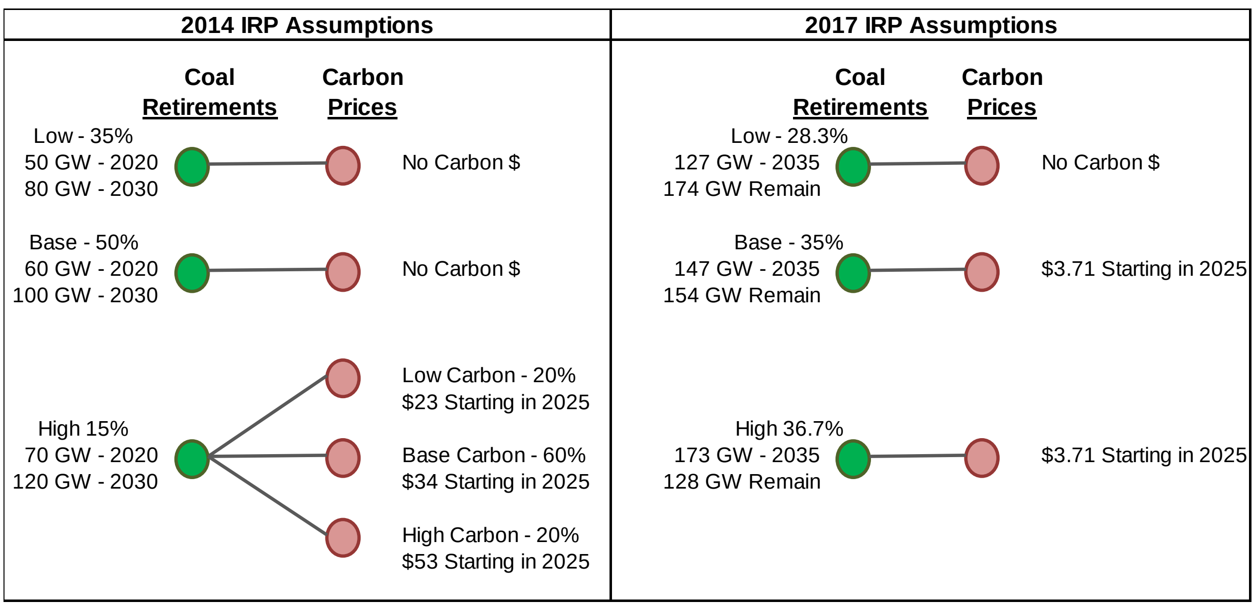
This framework provided a theme of discussions for our internal experts to identify the probable ranges of coal retirements and carbon prices that define our scenarios.

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[6]

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 regulations at the time of publishing the dataset used in 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 retirement 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 2017 IRP.

Figure 2.6 Coal Retirement Assumptions



Carbon Dioxide Emissions Prices[7]

In addition to coal plant retirements, an update to an explicit carbon price expectation and the timing of this price was reviewed. The price of carbon dioxide emissions is assumed to be zero in all years prior to 2025. The development of a carbon price

[6] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.060(5)(C)
[7] 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

included a review of several approches to projecting a carbon price including Synapse, IHS-Cera, EIA 2016, and PIRA. The approach that aligned most closely with the views of our subject matter experts was that of the IHS-Cera Rivalry scenario. Expectations for this scenerio included a greater role for natuarl gas, renewable energy, energy efficiencey programs and an overall evolution of energy technologies. The uncertainty of these factors led to many possible paths with which the chosen carbon price would be compatible. 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 more restrictive operations of coal facilities. Table 2.7 shows the values used in the current IRP analysis.

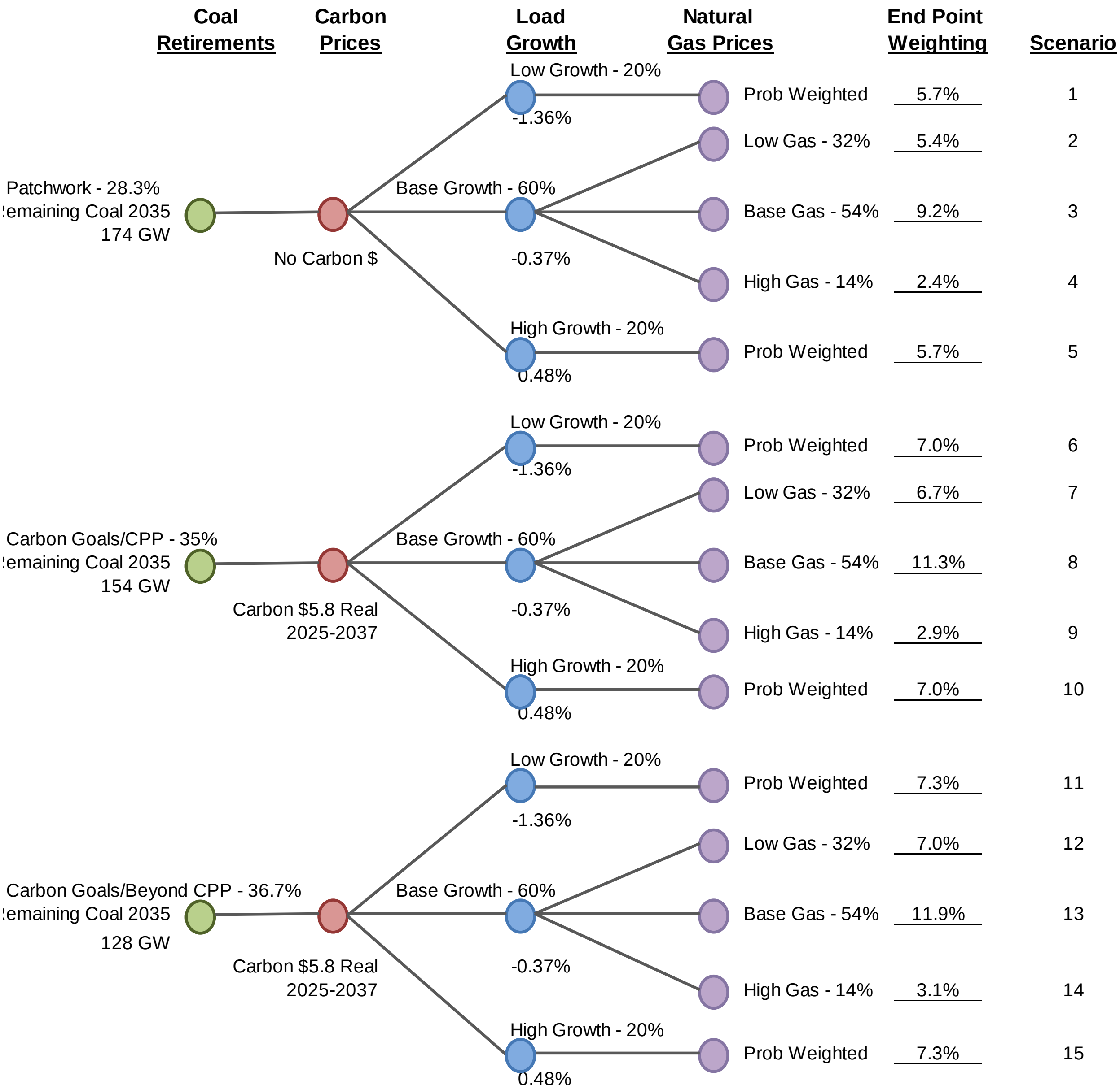
Table 2.7 Carbon Dioxide Emissions Price Assumptions

	2016 $/Ton Real			Nominal		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2025	$0.00	$3.11	$3.11	$0.00	$3.71	$3.71
2026	$0.00	$3.42	$3.42	$0.00	$4.17	$4.17
2027	$0.00	$3.77	$3.77	$0.00	$4.68	$4.68
2028	$0.00	$4.15	$4.15	$0.00	$5.26	$5.26
2029	$0.00	$4.57	$4.57	$0.00	$5.91	$5.91
2030	$0.00	$5.03	$5.03	$0.00	$6.64	$6.64
2031	$0.00	$5.54	$5.54	$0.00	$7.46	$7.46
2032	$0.00	$6.11	$6.11	$0.00	$8.39	$8.39
2033	$0.00	$6.73	$6.73	$0.00	$9.43	$9.43
2034	$0.00	$7.42	$7.42	$0.00	$10.60	$10.60
2035	$0.00	$8.18	$8.18	$0.00	$11.91	$11.91
2036	$0.00	$9.01	$9.01	$0.00	$13.39	$13.39
2037	$0.00	$9.93	$9.93	$0.00	$15.05	$15.05

2.7 Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation resources, 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



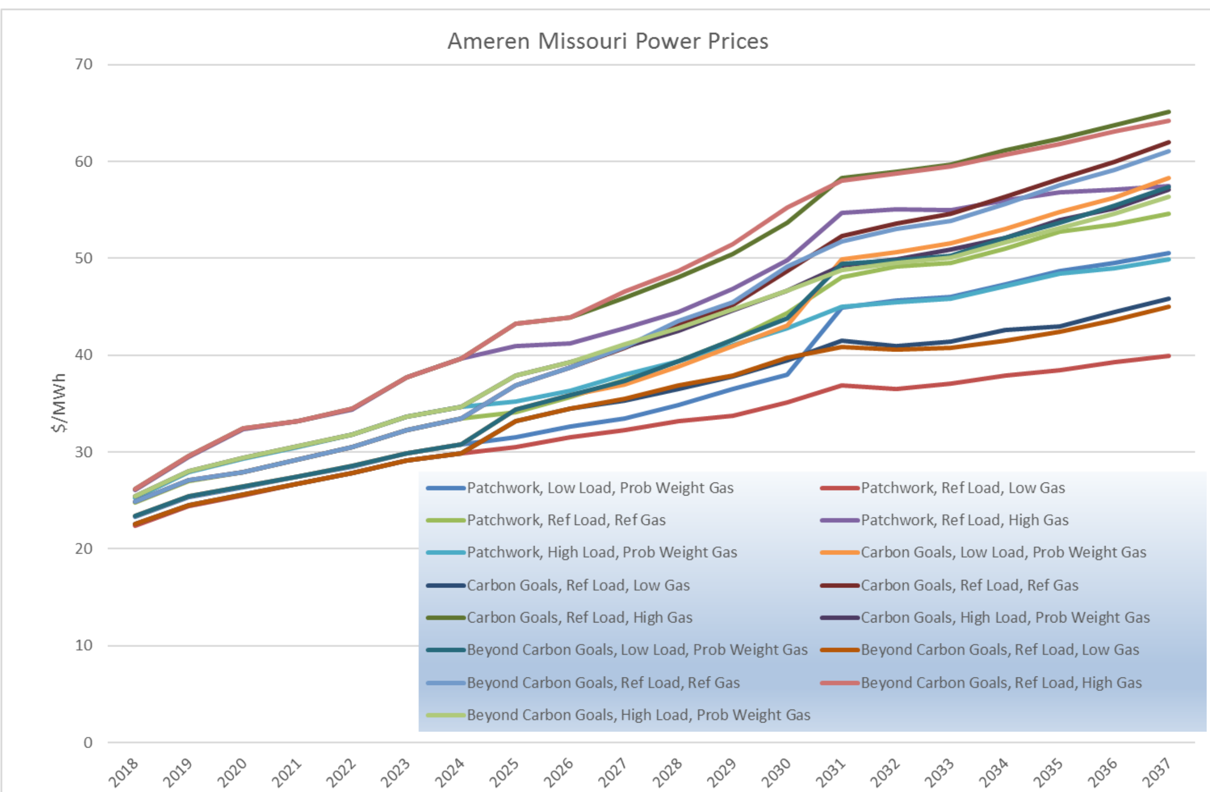
Electric Power Prices[8]

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 is the same model used to develop capacity prices and utilizes the same detailed simulation modeling and database setup to develop power prices. 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

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 yield different power price futures, which are shown in Figure 2.8 after basis adjustment as explained in the following section.

Figure 2.8 Scenario Power Prices



[8] 4 CSR 240-22.060(5)(G); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

Power Price Shaping

It is necessary to convert the around-the-clock (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 generation 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.

2.8 Compliance References