2. Planning Environment

Highlights

- *General economic conditions suggest slow growth, resulting in modest load growth.*
- *Natural gas prices continue to be driven by large domestic supplies of shale gas, and our assumptions span an approximate range of $2.40 - $3.60 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 9 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 before the onset of the current pandemic. Ameren Missouri's expectations continue to reflect relatively stable longer term economic growth, but at a slower pace than has been observed historically, in the 2 - 2.5% range annually for the gross domestic product ("GDP"). Generally, demographic factors present the single largest long-term challenge to growth. A key component to long-term economic growth is an expanding labor force, and as the Baby Boomer generation continues to enter early retirement, growth in the labor force is expected to be lower than historical trends. 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 and assuming a relatively short recovery from the current pandemic-induced recession.

Ameren Missouri's outlook for the local economy in 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. 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]

Aggressive monetary policy actions, including the massive increase in the Federal Reserve balance sheet along with the establishment of nine new credit-granting facilities, have helped to blunt the immediate economic impacts of Covid-19. These measures along with fiscal policies like the CARES Act will continue to significantly increase the Fed's balance sheet over the short term. Looking forward as the world seeks solutions to the Pandemic crisis and the economy begins to regain its footing, the accommodative stance of monetary policy will provide a stabilizing force to aid it achieving the long term outlook of 2% growth.

[1] 20 CSR 4240-22.060(2)(B); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(5)(B)

For this IRP, long-range interest rate assumptions are based on the December 1, 2019, semi-annual Blue Chip Financial Forecast. This forecast is a consensus survey of 44 economists from numerous firms including banks, investment firms, universities, and economic advisors. Table 2.1 shows the analyst expectations for the yield on 30-year Treasuries annually for 2021-2025 and a five-year average estimate for 2026-2030.

Table 2.1 Forecast Yield: 30-year Treasury

**** Table is Confidential in its entirety ****

Long-term allowed return on equity ("ROE") expectations for Ameren Missouri were developed using the projected long-term risk-free interest rate identified for 2026-2030 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 30 year treasury rates. 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 ******___******% as shown in Table 2.2.

Table 2.2 Projected Allowed ROE

**** Table is Confidential in its entirety ****

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 6.04%. 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).

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 expansion 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.

The updated planning case projects Ameren Missouri's retail sales to grow by 0.7% over the 20 year planning period, with retail peak demand to grow by 0.5% over that same period. This planning case expectation is an increase from our last IRP and reflects an updated view on economic conditions, energy efficiency programs and penetration of

[2] 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(A); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

customer owned renewable generation. One of the most significant changes that affects this forecast is an increase in expected adoption of efficient electrification like electric vehicle adoption.

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 a reduced adoption of customer owned generation an annual average growth rate of 1.0% was assumed.

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 0.1% 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 and efficient electrification 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 Federal Energy Regulatory Commission ("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 2019, indicates a planning reserve margin requirement of 18% (applied to peak demand) in 2021. Table 2.4 shows the year-by-year PRM requirement through 2029. Ameren Missouri has assumed that the PRM beyond 2029 remains at 18.3%.

Table 2.3 MISO System Planning Reserve Margins 2021 through 2029

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029
PRM Installed Capacity	18.0%	17.9%	17.9%	18.2%	18.2%	18.1%	18.2%	18.2%	18.3%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for wind and solar generation. The capacity credit is applied to the net output capability (in MW) of a wind/solar farm to determine the amount of capacity that can be counted toward the PRM for resource adequacy. The MISO value for wind capacity credit is based on the Planning Year 2020-2021 Wind & Solar Capacity Credit Report and is provided in Table 2.4. The solar capacity credit based on the same MISO report and is 50%.

Table 2.4 Wind Capacity Credit

Year	2021	2025	2030	2035	2040	2045	2050
Wind Capacity Credit	16.4%	15.7%	14.7%	14.1%	13.5%	13.1%	12.6%

2.5 Energy Markets

Energy market conditions that may affect utility resource planning decisions include prices for natural gas, coal, nuclear fuel, 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 continued its 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.

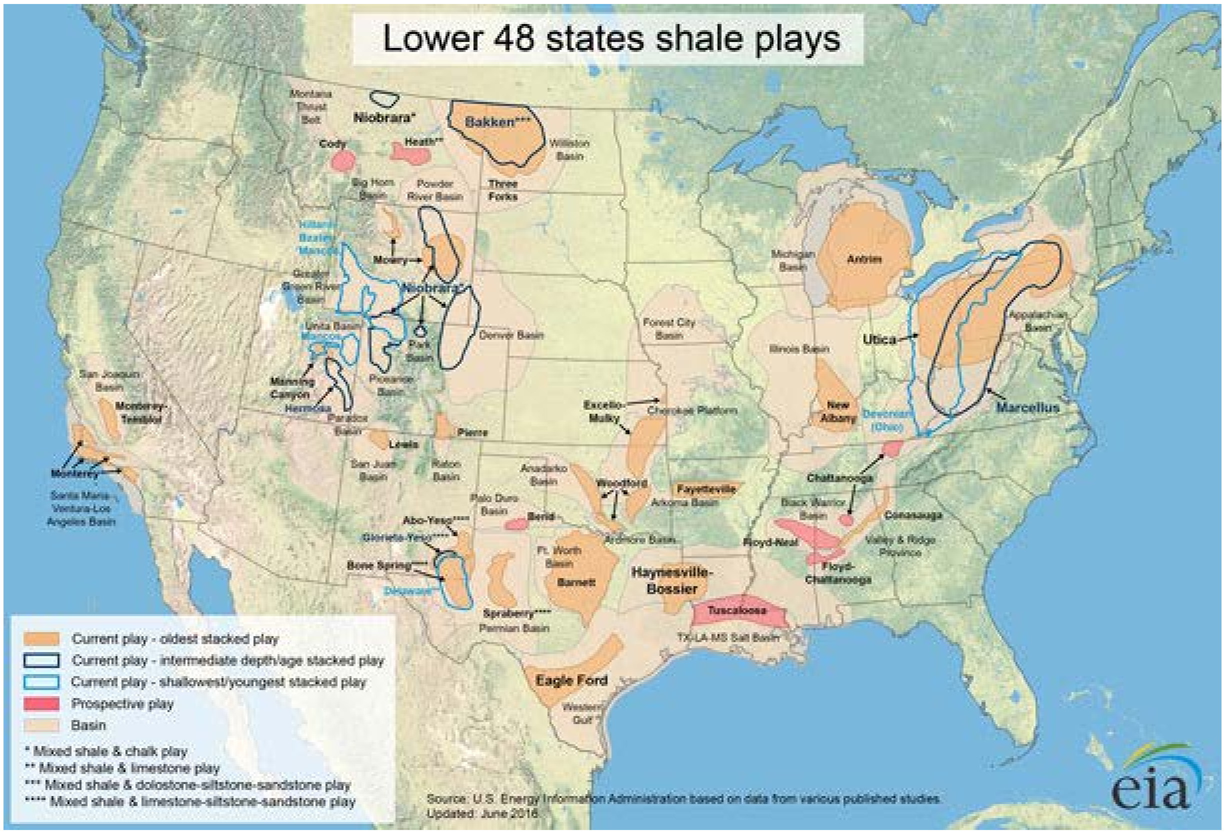
Natural Gas Price Drivers

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 continue to hold greater reserves than initially estimated. Natural gas production is expected to slow in the next few years to become more in line with demand. Production records continued to be set into 2020 reaching 94 Bcf per day prior to a Covid-19 induced slowdown. The pandemic depressed oil demand and resulted in a decline in associated gas production in the major oil plays. This lower production is expected to be temporary and the eventual recovery will be timed with the rebound in human mobility in the developed world. Regardless of the timing and magnitude of the return to gas demand growth, the ability to produce

[3] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D);
20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

incremental supplies at historically low prices will continue to be the dominant theme in natural gas supply.

Figure 2.1 North American Natural Gas



Demand – Residential and commercial demand remains flat while industrial demand is expected to grow. Electric generation continues to support gas markets especially when prices dip below $2.00 per MMBtu as gas-fired electric generation is the market balancing mechanism in the North American gas market. New gas fired unit development is declining with the increased deployment of wind and solar but still occurring, necessitated by continued coal and nuclear plant retirements. The bright spot for demand is liquefied natural gas ("LNG") exports. A Covid-19 related pause in exports is expected to end with full recovery by late 2020, and growth in exports is expected to continue in 2021.

Infrastructure – New pipeline projects continue to be developed and installed with the focus in Texas and the Gulf Coast to support LNG exports and de-bottleneck Permian supply. However, new gas pipeline infrastructure has become a high risk venture as state and local permitting difficulties, along with various Legal challenges have terminated several large projects in the Northeast. Even regions with a history of more constructive regulatory regimes are seeing increased permitting difficulties and legal challenges to new infrastructure. This trend will likely lead to the increased frequency and severity of regional price dislocations. Market conditions have not favored the build-out or expansion of storage capacity, creating the potential for larger variations in winter and summer gas pricing.

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 changes in gas supply and demand.

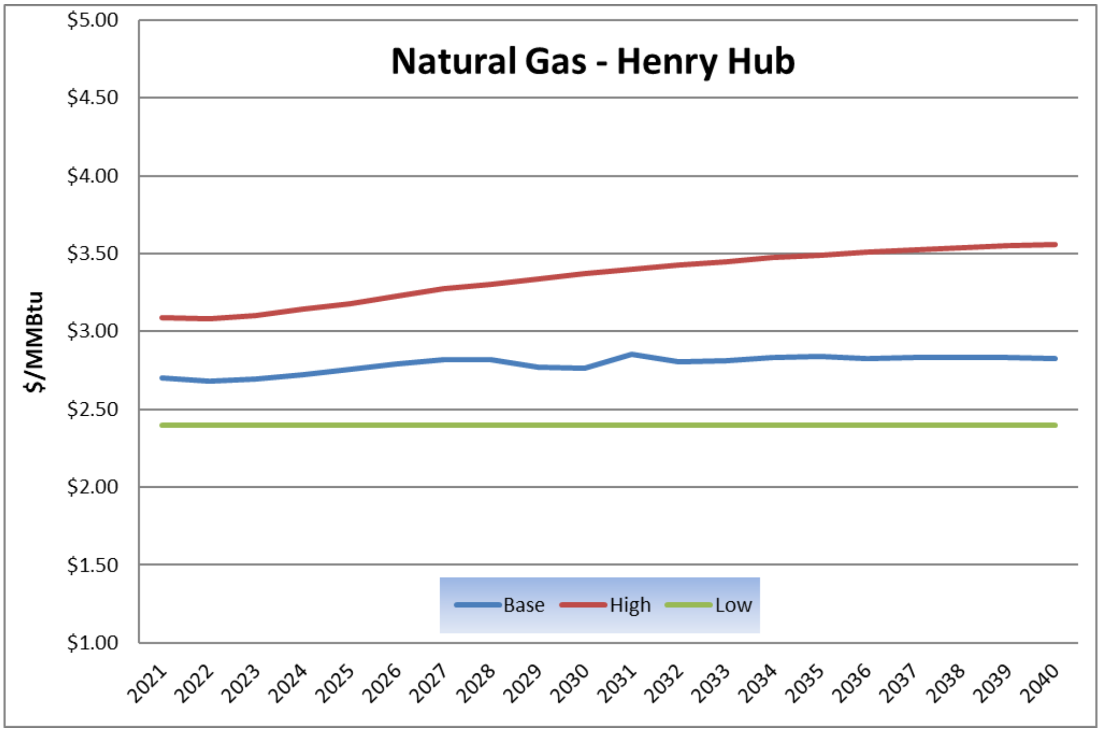
Natural Gas Price Assumptions

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: BTU Analytics, U.S. Energy Information Administration ('EIA"), and the Nymex Henry Hub market prices. These services, along with internal market knowledge of the natural gas industry, have helped to frame the long-term assumptions used in this IRP and identify 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 2.2.

Table 2.5 Natural Gas Price Assumptions ($/MMBtu)

	Real Gas 2020 $									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
High	$3.09	$3.08	$3.10	$3.14	$3.18	$3.22	$3.27	$3.30	$3.34	$3.37
Base	$2.70	$2.68	$2.70	$2.73	$2.76	$2.79	$2.82	$2.82	$2.77	$2.77
Low	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40
	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
High	$3.40	$3.42	$3.45	$3.47	$3.49	$3.51	$3.53	$3.54	$3.55	$3.56
Base	$2.85	$2.80	$2.81	$2.83	$2.84	$2.82	$2.84	$2.84	$2.83	$2.83
Low	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40

Figure 2.2 Natural Gas Price Assumptions



2.5.2 Coal Market[4]

Ameren Missouri's 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 Powder River Basin ("PRB") coal given that the vast majority of Ameren Missouri's current and expected coal supply will be sourced from this basin.

Coal Price Drivers

According to U.S. Energy Information Administration, the 2019 U.S. coal production was around 706 million tons. Going forward, U.S. coal supply and demand is expected to decline over the next 20 years with estimated supply to be in the range of 500-700 million tons per year. The assumptions defined for a potential CO_2 tax, and other demand-side drivers, are discussed independently. All U.S. thermal coal demand will likely be negatively impacted by coal plant retirements and ongoing competition with alternative energy sources. PRB coal production is anticipated to be the least impacted U.S. coal basin due to cost advantages compared to other U.S. coal regions. Long term supply of ultra-low sulfur PRB coal is expected to be 100-250 million tons per year. PRB exports in the next 20 years are projected to stay flat and will have minimal impact on demand.

[4] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

PRB pricing is influenced by many factors, including the following:

- Mining strip ratios (overburden vs. coal seam) are expected to increase
- Governmental Imposition charges
- Fixed mining costs being spread across smaller production levels
- Cost of materials, supplies and capital equipment
- Increasing coal haul distances from coal pit to load-out
- Eventual interference with the railroads Joint Line
- Productivity improvements
- Coal reserve lease availability and costs
- Coal demand

As PRB mining progresses from east to west, coal seams generally dive deeper such that strip ratios will increase by a substantial amount. Except for one PRB mine, the western mining progression will likely also infringe upon the "Joint Line" railroad (operated by both the Burlington Northern Sante Fe ("BNSF") and Union Pacific ("UP") railroads) such that the majority of mines will need to address the significant cost of crossing the railroad.

Coal prices may vary from the base forecast due to the drivers mentioned above and others. Examples of other drivers that may impact coal prices are bankruptcies, joint ventures, railroad business models, new mining, generation or environmental technology, changes in the electric grid, balance between coal supply & demand, and electric load loss/growth.

Ameren Missouri's 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). The supply for this range of product is anticipated to be available in the long-term forecasts, however, factors beyond Ameren Missouri's control may impact availability.

Coal Price Assumptions

In the development of the coal price forecasts for use in the 2020 IRP a low, base and high forecasts were utilized for PRB coal delivered to the existing coal-fueled Ameren Missouri energy centers. This process included an assessment of current and future expectations of PRB coal prices (Freight on Board or Free on Board ("FOB") at the mine) and 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 Wood Mackenzie, U.S. Energy Information Administration and S&P Global were reviewed, 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)

****Table is Confidential in its entirety****

2.5.3 Nuclear Fuel Market[5]

Nuclear Fuel Price Drivers

Ameren Missouri relied on Ux Consulting Company ("UxC") for nuclear fuel forecasts as we have for prior IRP analyses. UxC provided annual price forecasts for uranium ("U_3O_8"), conversion ("UF_6"), 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

[5] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

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 Ux Consulting Company. UxC was used in this role previously for the 2008, 2011, 2014 and 2017 IRPs. The Surfnonline model by Huxtable Consulting 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 2.3 shows the nuclear price forecast for a new nuclear unit.

Figure 2.3 Nuclear Fuel Price Forecasts

****Table is Confidential in its entirety****

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 expected market capacity price forecast used in the 2020 IRP is based on a combination of historical prices transacted in MISO and the limited (one to two years) visable forward market for capacity. This combination of historical actual tranactions and forward looking market information is averaged over a 10 year period to develop an expected long run average price for capacity going forward in the MISO market. This financial market based capacity curve differs from the 2017 IRP market based capacity curve, developed using the Midas production cost modeling software. Given historic volatility in capacity markets, it was determined to use a long run average price series for the 2020 IRP. This price series is used for the integration and risk analysis as discussed in Chapter 9.

Forward looking cost curves for energy and capacity are also used in the screening and cost-effectiveness analysis of demand side resource programs, as discussed in greater detail in Chapter 8. In contrast, the purpose of a screening or cost effectiveness analysis is to identify the value of demand side resources relative to a planning environment without those same demand side resources. To this end, a separate capacity price curve was also developed to be used in future demand-side resource cost effectiveness analyses. This curve is a combination of the market-based capacity price forecast mentioned above and the cost of new entry ("CONE") value published by MISO. In determining when to move to a CONE value, Ameren Missouri reviewed a planning scenario in which there were no more DSM programs beyond MEEIA Cycle 3 and with retirement of 6 coal-fired units by the end of 2028. The first year that a new supply-side resource would be needed in such a scenario to strictly meet MISO planning reserve requirements was found to be 2029 as shown in Figure 2.4. Therefore, Ameren Missouri assumed market based prices through 2028 and CONE value (adjusted for inflation) starting in 2029. This method and cost curve may be used for future screening or cost effectiveness analysis purposes, instead of explicit capacity modeling, in order to ensure the inclusion of cost equavilant measures in the portfolios. The integration and risk analysis then serves as the holistic analytical test for cost effectiveness when compared to supply-side resource alternatives.

Figure 2.4 Capacity Position without Further DSM

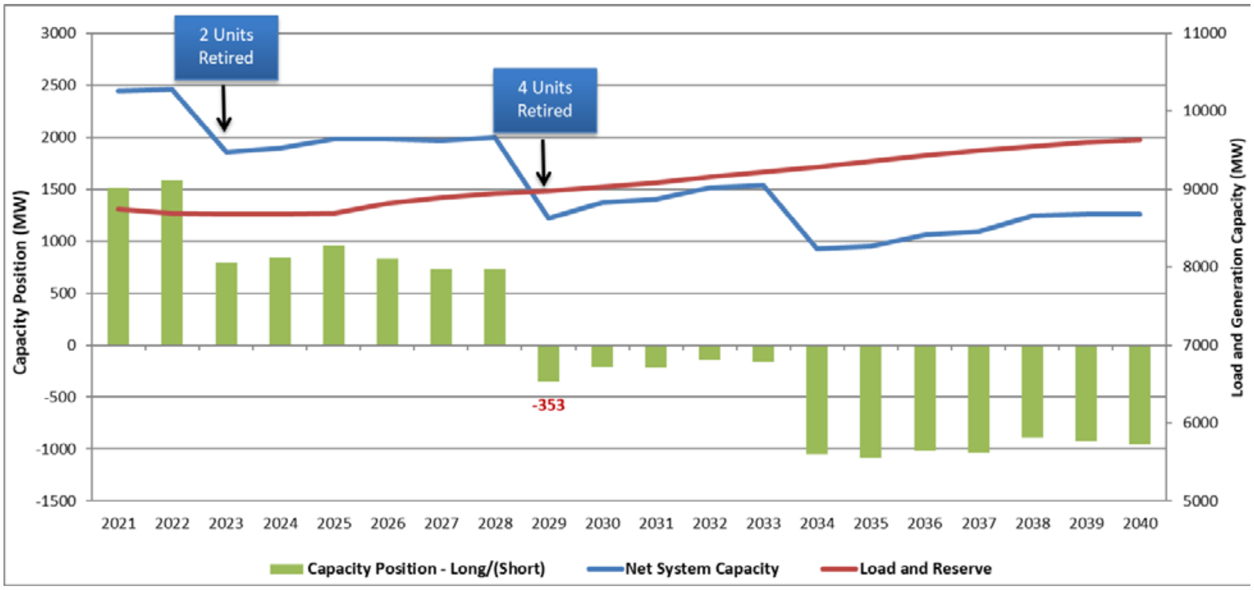
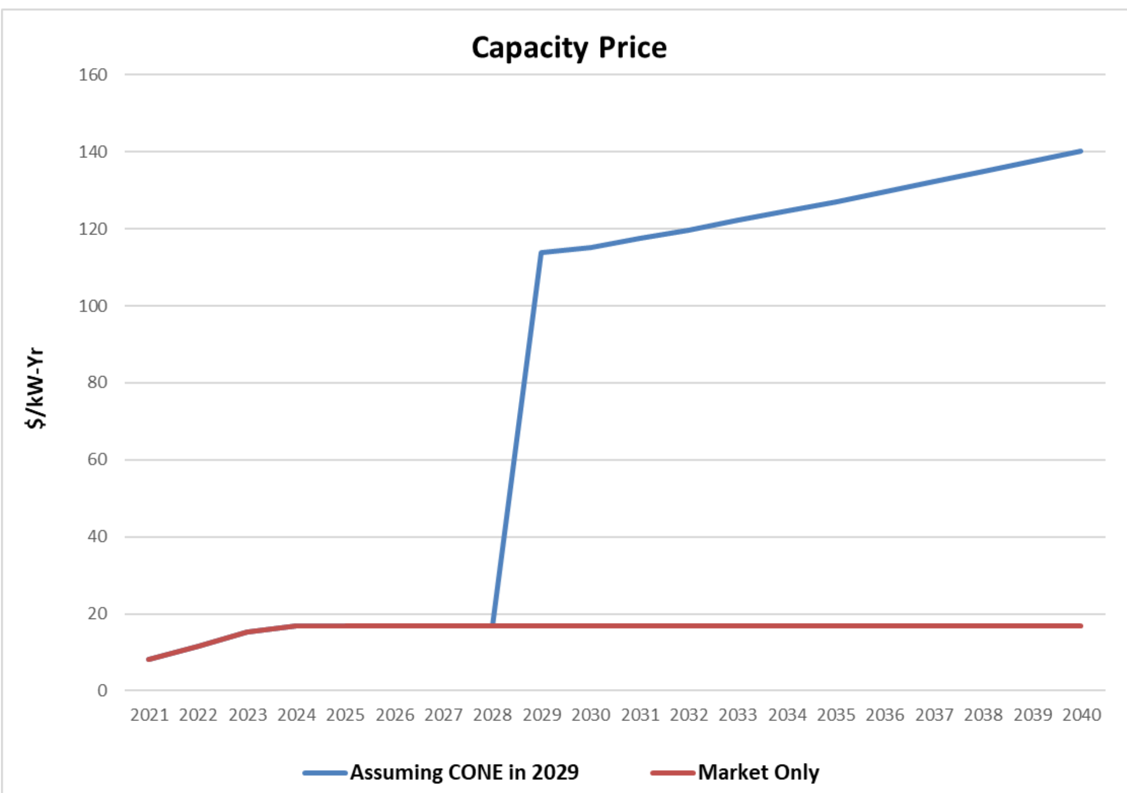


Figure 2.5 shows the market-based capacity price curve used for integration and risk analysis as discussed in Chapter 9 and the hybrid capacity price curve for DSM screening purposes.

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 investor-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 greenhouse gas ("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 dioxide
  - Cross 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.

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 these regulations that have been finalized by the EPA. To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined sources like the most recent EIA – AEO report along with other sources.

We identified three general paths forward by which GHG policy would be implemented;

- "Status Quo" Current ACE rule with no additional price on carbon.
- "Measured Decarbonization" moderate steps in establishing a carbon price
- Aggressive Decarbonization" greater severity in valuing carbon

Our internal experts used this framework to identify the probable ranges of carbon prices that define our scenarios. Through this process an updated set of assumptions was developed to reflect environmental policy through the timing, magnitude and probability of an explicit price on carbon dioxide emissions.

Carbon Dioxide Emissions Prices[6]

Updated expectations for an explicit carbon price and timing were reviewed and revised for this IRP. The development of an assumed range of carbon prices included a review of several viewpoints on a carbon price including those from Synapse, 2019 EIA AEO, The Climte Leadership Council's Report - Exceeding Paris How the Baker-Shultz Carbon Dividents Plan would Significantly Exceed the U.S. Paris Commitment, The Social Cost of Carbon and various recent utility IRP's including those filed by Duke, AEP, TVA and Excel. The assumed price for carbon dioxide emissions remains zero in all years prior to 2025 based on near-term consideration of potential political outcomes and how they would influence legislative policy. Table 2.7 shows the values used in the current IRP analysis.

Table 2.7 Carbon Dioxide Emissions Price Assumptions

	2020 $/Short Ton Real			Nominal $/Short Ton		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2025	$0.00	$1.13	$3.23	$0.00	$1.25	$3.57
2026	$0.00	$2.22	$6.33	$0.00	$2.50	$7.13
2027	$0.00	$3.27	$9.31	$0.00	$3.76	$10.70
2028	$0.00	$4.28	$12.17	$0.00	$5.01	$14.26
2029	$0.00	$5.24	$14.92	$0.00	$6.26	$17.83
2030	$0.00	$6.16	$17.55	$0.00	$7.51	$21.39
2031	$0.00	$6.25	$18.04	$0.00	$7.77	$22.43
2032	$0.00	$6.34	$18.55	$0.00	$8.04	$23.52
2033	$0.00	$6.43	$19.08	$0.00	$8.32	$24.68
2034	$0.00	$6.52	$19.63	$0.00	$8.61	$25.90
2035	$0.00	$6.62	$20.21	$0.00	$8.91	$27.20
2036	$0.00	$6.72	$20.81	$0.00	$9.23	$28.57
2037	$0.00	$6.82	$21.44	$0.00	$9.55	$30.03
2038	$0.00	$6.93	$22.10	$0.00	$9.90	$31.57
2039	$0.00	$7.04	$22.79	$0.00	$10.25	$33.20
2040	$0.00	$7.15	$23.51	$0.00	$10.62	$34.93

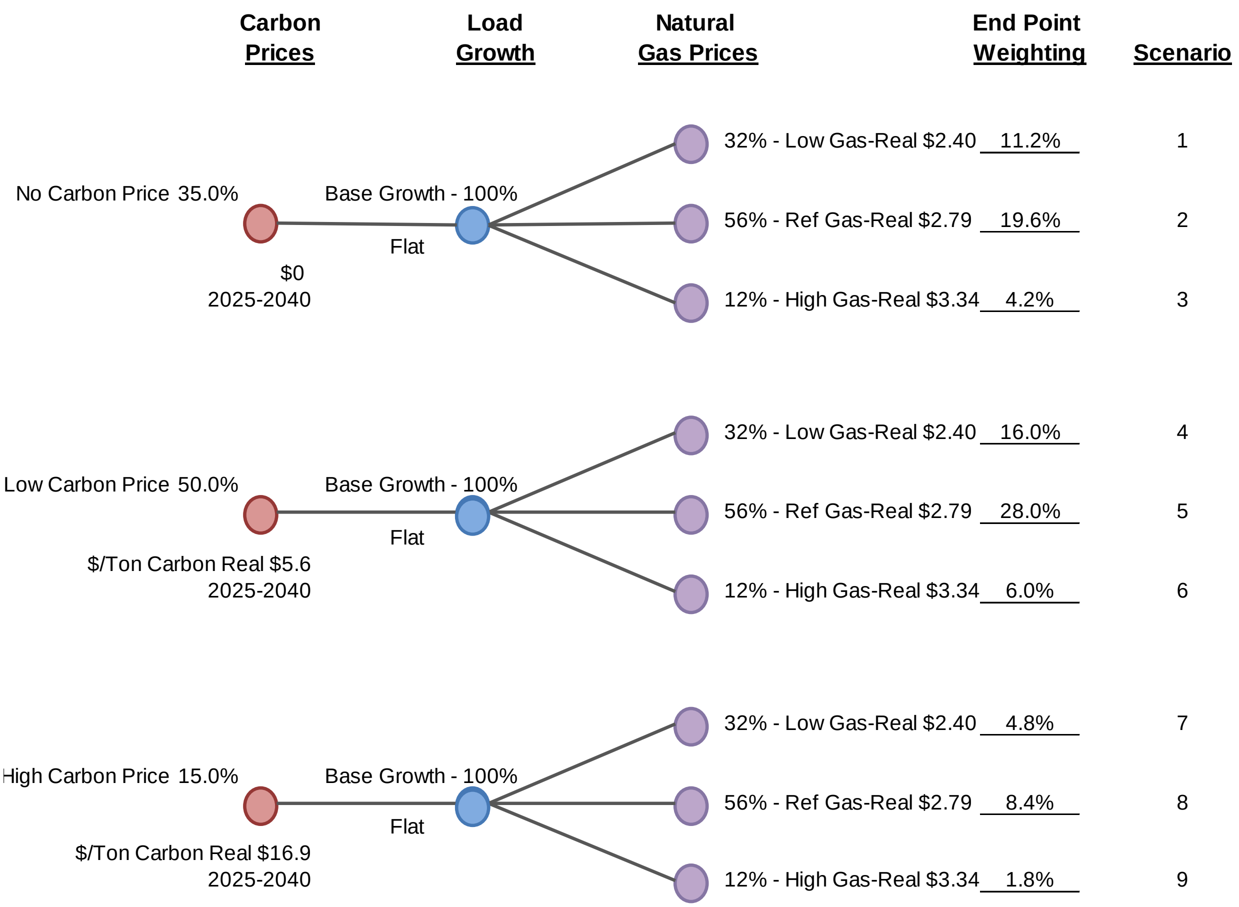
2.7 Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation resources, and natural gas prices. Using our assumptions for carbon prices and natural gas prices we developed scenarios based on combinations of these assumptions. The

[6] 20 CSR 4240-22.040(2)(B); 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(D); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(C); 20 CSR 4240-22.060(5)(H); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

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 2.6 shows the final scenario tree.

Figure 2.6 Final Scenario Tree



Electric Power Prices[7]

To support our analysis of alternative resource plans, as described in Chapter 9, we developed forward price forecasts at the Indiana Hub using modeling software provided by Ventyx and commonly referred to as “Strategic Planning” or “MIDAS”. This detailed simulation modeling and database setup is used to develop power prices. To ensure that

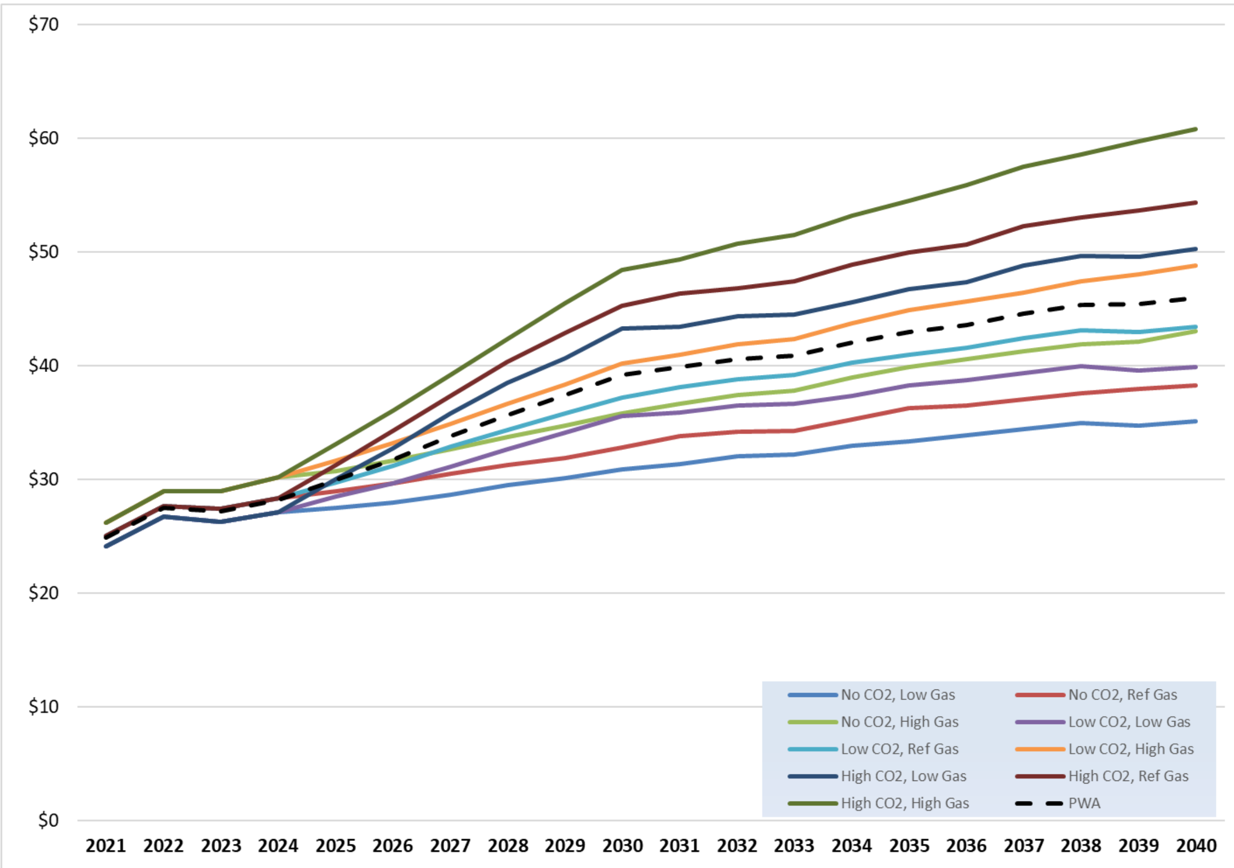
[7] 20 CSR 4240-22.060(5)(G); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

a range of possible future power prices was 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;

- Natural gas prices
- An explicit price on carbon dioxide emissions

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 2.7 after basis adjustment as explained in the following section.

Figure 2.7 Scenario Power Prices



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 2017 day-ahead price curve applicable to Ameren Missouri's base load generators. 2017 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