Exhibit No.:	
Issue(s):	Resource Planning
Witness:	Matt Michels
Type of Exhibit:	Sur-Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	EF-2024-0021
Date Testimony Prepared:	April 4, 2024

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EF-2024-0021

SUR-SURREBUTTAL TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
April 2024

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SUR-SURREBUTTAL TESTIMONY

OF

MATT MICHELS

FILE NO. EF-2024-0021

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matt Michels. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. By whom and in what capacity are you employed?

A. I work in Ameren Services Company's Corporate Strategy and Enterprise Risk Management Department as Director of Corporate Analysis. The Corporate Strategy and Enterprise Risk Management Department provides various corporate support services to Ameren Corporation and its subsidiaries, including Ameren Missouri.

Q. Are you the same Matt Michels who submitted direct and surrebuttal testimony in this case?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. To what testimony or issues are you responding?

A. I am responding to new issues and positions raised in the surrebuttal testimonies of Staff witnesses Claire Eubanks and Shawn Lange. Ms. Eubanks makes several assertions regarding the Company's analysis of retirement of Rush Island Energy Center ("RIEC") vs. retrofitting the plant with flue gas desulfurization ("FGD") pollution control equipment presented in my direct testimony, assertions that were not included in her rebuttal testimony. These include issues raised by Staff in a prior case in which the Missouri Public Service Commission ("MPSC") was considering applications made by the Company for certificates of convenience and necessity ("CCN") for solar generation projects, issues that were certainly known by Staff at the time it filed its rebuttal testimony in this case. Mr. Lange's surrebuttal testimony is a retread of testimony presented in that same solar CCN case criticizing the assumptions the Company uses to reflect the impact of future climate and environmental regulations over the 20-year planning horizon, specifically the Company's range of carbon price assumptions, disagreements with my direct case analysis which Staff failed to rase in its rebuttal.

III. THE MANNER IN WHICH AMEREN MISSOURI ACCOUNTED FOR CARBON REGULATION IS REASONABLE AND APPROPRIATE FOR ITS RETIREMENT VERSUS RETROFIT DECISION

Q. Please describe Mr. Lange's disagreement regarding the manner in which the Company accounted for carbon regulation in your direct case analysis.

A. Mr. Lange's main point of contention is that he disagrees with the Company's use of carbon price assumptions to analyze the cost and resource implications of potential climate and environmental policy rather than specific emission limits, implying that the use of carbon price assumptions for this purpose is somehow inferior to modeling specific limits and that the Company's retirement versus retrofit decision for RIEC is somehow suspect as a result. In making his claims and implications, Mr. Lange asserts the following:

1. The U.S. Environmental Protection Agency's ("EPA") so-called "Good Neighbor Rule" governing power plant emissions of nitrogen oxides ("NOx") during the summer ozone season, defined by the EPA's Cross-state Air Pollution Rule, employs an emission allowance cap-and-trade system. The implication is that this approach should be preferred to assumptions for a price on carbon

dioxide emissions.[1] Mr. Lange notes a similar mechanism that is employed by EPA's Acid Rain program.

2. The EPA's current proposed rule for greenhouse gas ("GHG") emissions from power plants employs emission standards for individual units based on deployment of technologies that EPA asserts are feasible.[2]
3. Assumed carbon prices result in increases in assumed market prices for power, resulting in an economic advantage for renewable resources like wind and solar.[3]
4. Higher carbon prices will therefore drive a buildout of renewable resources.[4]
5. Emission limits would cause more renewables to be added to the grid, and zero-cost renewables would act to reduce market power prices.[5]

Q. Please summarize your critique of the assertions made by Mr. Lange.

A. Mr. Lange's disagreements with the Company's approach boil down to his own preferences as to how modeling should be done, modeling that neither he nor anyone else at Staff performs to my knowledge. He provides no evidence to support that his preferred method is superior. He seems to understand that both the Company's approach and his preferred approach result in similar dynamics in power markets – reduced generation from fossil-fueled resources and increases in renewable generation. At the same time, he appears to ignore key similarities in the way the two approaches work, such as the existence of a price on carbon emissions under a cap-and-trade regime and the suppressive effects on power prices of significant renewable expansion. Taking his key assertions, as outlined above, one at a time:

1. While EPA has indeed employed cap-and-trade mechanisms to regulate emissions, such mechanisms are accompanied by an

[1] File No. EF-2024-0021, Shawn E. Lange Surrebuttal Testimony, p. 2, ll. 13-16.
[2] File No. EF-2024-0021, Shawn E. Lange Surrebuttal Testimony, p. 2, l. 16, to p. 3, l. 1.
[3] File No. EF-2024-0021, Shawn E. Lange Surrebuttal Testimony, p. 3, ll. 7-10.
[4] File No. EF-2024-0021, Shawn E. Lange Surrebuttal Testimony, p. 4, ll. 2-3.
[5] File No. EF-2024-0021, Shawn E. Lange Surrebuttal Testimony, p. 3, ll. 10-13.

allowance market with a price for allowances. The Company has indicated in its 2023 IRP that it does not specify a particular mechanism for pricing and that it could include such a cap-and-trade system, a carbon tax, a clean energy standard with an alternative compliance payment, a Regional Transmission Organization ("RTO") market mechanism, or any other mechanism through which a carbon price may be established, whether through legislation, regulation, or some other means.[6]

2. The EPA's current proposed GHG rule does not include a cap-and-trade mechanism, nor does it cap total carbon emissions. It establishes emission standards for fossil-fueled generators but does not limit the number or size of such generators. While EPA claims that the rule will reduce overall emissions, it cannot be characterized as an emissions cap. Because the history of carbon regulation in the U.S. to date has been characterized by a series of legal challenges (e.g., Clean Power Plan, Affordable Clean Energy rule), and because the topic remains contentious today, the future of the proposed rule is uncertain. If the rule takes effect and remains in effect through the planning horizon, it will impose costs on fossil-fueled generation, making it less economically competitive, while benefiting renewable and other cleaner forms of generation. The proposed rule may still be supplemented with further regulatory

[6] See Schedule MM-SS1 – Ameren Missouri 2023 IRP Chapter 2 – Appendix A, p. 13.

action. If the rule does not take effect, the pressure to regulate GHG emission will continue, and the form it takes cannot be known today with any certainty. This pressure and likely eventual regulation will continue to negatively impact the economic case for investments to extend the life of coal fired plants like Rush Island. Either way, it is reasonable to analyze long-term impacts of climate and environmental policy through the use of a price on carbon emissions.

3. While carbon prices, whether they take the form of a carbon tax or emission allowance prices or prices formed through some other mechanism, do increase offers for fossil-fueled generators into markets like the Mid-continent Independent System Operator ("MISO") market, their effect on market prices depends on the hours in which such units are the marginal units that set the price for power. Any regulatory regime that incentivizes renewables and penalizes fossil generators is going to result in an advantage for renewable resources and decrease the cost-effectiveness or competitiveness of coal-fired generation like Rush Island.
4. The relative advantage created for renewables under any such policy regime is most likely going to drive a buildout of renewables, which in turn displaces, and negatively impacts the economics of, fossil-fueled generation like Rush Island. This is true whether the regulatory mechanisms selected include a carbon tax, a cap-and-

trade regime, or some other form of regulation. With any such policy or combination of policies in place, the drive will be toward more renewable energy and less fossil-fueled generation like Rush Island.

5. Regardless of the mechanisms employed, the addition of significant renewables on the grid is going to have a suppressive effect on prices, particularly in hours when renewable generation exceeds demand. The Company's carbon pricing assumptions reflect this based on the modeling performed by Charles River Associates ("CRA") and presented in Schedule MM-SS1.

Q. You mentioned that EPA's proposed GHG rule could be supplemented with further regulatory action. Could that include some mechanism that establishes a price on carbon emissions?

A. It most definitely could, and the ongoing pressure to regulate, not just the power sector but multiple sectors of the economy, appears to point in that direction. It is important to recognize that the focus of potential climate policy has continued to broaden to sectors beyond power over the last decade, and in the last few years in particular, as emissions from transportation, industry and heating draw more attention. It is also important to recognize that many policy makers have become more focused on time-oriented goals for achieving economy-wide decarbonization, such as policies seeking to achieve net zero carbon emissions by 2050. Taken together, this approach to climate policy often reflects a desire to ensure consistency in application across sectors and efficiency in achieving reductions cost effectively, something that can best be achieved through policies that place an explicit price on carbon emissions. This has factored into decisions by Ameren

Missouri and others to focus on ranges of prices on carbon emissions to represent the effects of potential climate policy.

Q. How has the Company modeled carbon regulation in its resource planning, including its triennial IRP filings?

A. At least as far back as the 2014 triennial IRP, we modeled carbon regulation by using a carbon pricing assumption, just as we did with the RIEC retire versus retrofit analysis. It is important to note that the RIEC retire versus retrofit analysis *is* a resource planning analysis: should RIEC remain a resource on the system if scrubbers must be added?

Q. Did Staff claim in any of those IRP dockets that there were shortcomings in the Company's carbon regulation modeling?

A. No, and that includes in the 2023 IRP for which we took the same approach.

Q. What does Staff's failure to raise these issues as either a deficiency or a concern indicate?

A. At a bare minimum, it demonstrates that whatever issues Staff may have are not major issues. The reason is that under the Commission's IRP rules, the IRP would be deficient if it reflects "major deficiencies in the methodologies or analyses . . . that would cause the . . . utility's resource acquisition strategy to fail."[7] And under those same rules, a concern should be identified if there is a "major concern… with the methodologies or analyses….that may prevent the . . . utility's resource acquisition strategy from effectively fulfilling the objectives of Chapter 22."[8] Both the Company's preferred resource plan ("PRP") submitted in June 2022 and its PRP submitted in September of last year reflect

[7] 20 CSR 4240-22.020(9).
[8] 20 CSR 4240-22.020(6).

retiring RIEC and not retrofitting it. The PRP is a component – probably *the key* component – of the resource acquisition strategy.[9] Consider that the "fundamental objective" of resource planning is for utilities to "provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates" and that in this fundamental objective "requires the utility" to "(B) use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan."[10] Despite these provisions of the Commission's IRP rules, the Staff did not consider its carbon price modeling issues to be major in any way, did not therefore find that the manner in which the Company modeled carbon regulation could cause the resource acquisition strategy to fail, and did not find that the Company's carbon regulation modeling approach would undermine the *fundamental* objective of resource planning. Under the rules just cited, however, if there actually did exist a major deficiency or major concern, Staff should have raised it. That it didn't demonstrates whatever concern Staff may have with carbon pricing assumptions is not a major one.

Q. Has Staff raised these issues before?

A. Once, when it opposed the renewable projects in File No. EA-2023-0286.

Q. Did the Company respond to the issues raised by Staff in that case?

A. Yes. I sponsored surrebuttal testimony in that case, which included the Company's response to the criticisms raised by Staff. I would have attached my surrebuttal testimony from that case to my rebuttal testimony in this case had Staff raised these disagreements with my direct case analysis in its rebuttal testimony.

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[9] 20 CSR 4240-22.020(51) ("Resource acquisition strategy means a preferred resource plan…").
[10] 20 CSR 4240-22.010(2).

Q. Does Mr. Lange acknowledge or address any of the arguments you presented in the solar CCN case?

A. No, not in any explicit way that I can gather from reading his surrebuttal testimony.

Q. Please describe the Company's use of carbon pricing assumptions.

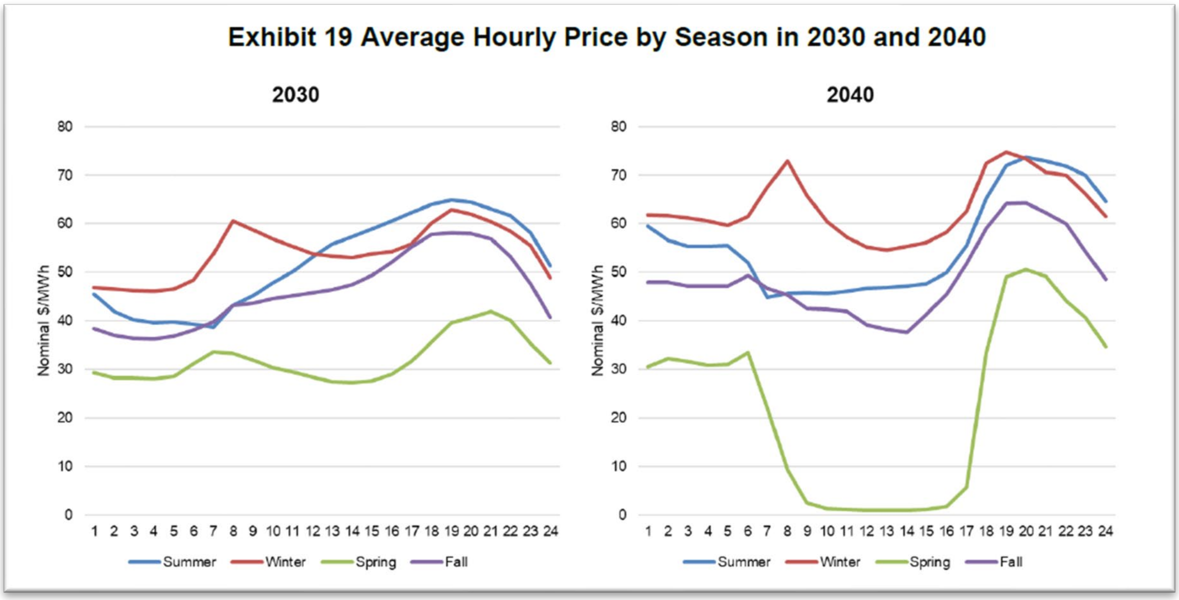
A. As I noted previously, the Company has used assumptions for carbon prices to represent ranges of potential climate policy over the planning horizon in its IRP analyses dating back to at least 2014. Prior to 2014, the Company experimented with approaches that accounted for more explicit forms of climate policy, finding that such explicit assumptions could quickly become outdated as policy proposals changed, including as a result of what have become routine legal challenges regarding this type of policy. It is important to note that when modeling explicit emission limits, it is typical for dispatch models to solve for meeting such limits through a process that establishes a price on emissions of the subject pollutant and iterates to find the price that results in compliance with the emission limit. As a result, a price on emissions is established ***regardless*** of whether the modeling begins with such a price or calculates it to meet an emission limit, further demonstrating that Staff's claim that using a carbon price unfairly disadvantages fossil-fueled resources is simply wrong.

For its 2023 IRP, Ameren Missouri used the services of CRA, a respected consulting firm with expertise in energy market modeling and analysis, to develop a set of power price scenarios defined by ranges of key inputs – load growth, natural gas prices, and carbon prices. As I noted previously, the carbon price assumptions used by the Company are not based on one specific form of climate policy. Rather, the range of carbon price assumptions represents the potential for imposing costs on fossil-fueled resources via a host of potential regulatory, market, or other mechanisms. These may include a carbon tax, a cap-and-trade regime with a price set through a market for emission allowances, a clean energy standard with an alternative compliance payment, a mechanism established by a RTO, or some other mechanism. Using assumptions that are somewhat independent of the specific policy that may be in effect in the future obviates the need to attempt to accurately predict what kind of policy regime will be in place throughout the planning horizon while considering a range of potential impacts from any kind of future climate policy.

As discussed in Schedule MM-SS1 (the CRA report), the Company's assumptions for carbon prices were used by CRA to develop future power price scenarios to be used by the Company for modeling. CRA performed capacity expansion modeling for the U.S. eastern interconnect based on different combinations of the key driver assumptions I mentioned previously. CRA then modeled the dispatch of resources in the eastern interconnect, including in MISO, to determine future power prices for each combination, or scenario. Because CRA's modeling accounts for all resources added to the grid, its price modeling reflects the impact of all resources on power prices. This includes the effect of significant renewable expansion on power prices, as illustrated in the charts in Figure 1 below from CRA's report.[11] Note the significant change in power prices during the middle part of the day from 2030 to 2040, particularly during spring, when power prices approach zero. These very price impacts have been reflected in the Company's IRP modeling.

[11] Schedule MM-SS1, p. 24.

Figure 1 – Average Hourly Prices by Season (2030 and 2040)



Q. Did CRA assess the reasonableness of Ameren Missouri's carbon price assumptions?

A. Yes. CRA reviewed Ameren Missouri's range of carbon prices and compared them to assumptions used by peer utilities, including Excel, AEP, CMS, Entergy, and PacifiCorp. CRA concluded that it was appropriate to use carbon pricing assumptions to represent the impact of potential future climate policy and that the Company's range of carbon price assumptions was reasonable based on comparison to peer utilities.[12]

Q. You mentioned that a cap-and-trade mechanism for regulating emissions would result in a price on carbon emission. Does Mr. Lange demonstrate an awareness of this fact?

A. Yes. In his deposition by Ameren Missouri in File No. EA-2023-0286, Mr. Lange explicitly recognized that a cap-and-trade mechanism would result in an established

[12] Schedule MM-SS1, p. 14.

price on carbon emissions, that this price would be included in the offers the Company makes for units into the MISO market, and that this would have a resultant effect on the market price for power:[13]

Page 136:

19· · · Q.· ·But in both those cases, the dispatch cost of
20· the fossil unit goes up.· It goes up if you use a
21· carbon price, and it goes up if you have a cap and
22· trade with CO2 allowances.· Right?· Either way you
23· model it, the dispatch cost is going to go up.· Right?
24· · · A.· ·Under your hypotheticals, yes.

Q. The implication Staff seems to be driving at by filing Mr. Lange's surrebuttal testimony is that a different approach to carbon regulation modeling might have led to a different RIEC retire versus retrofit decision. Is that implication true?

A. No, it is false. To demonstrate why it is false, I have now calculated the impact on the updated analysis provided in my surrebuttal testimony of having no carbon regulation in place at all, which completely removes from the debate how carbon regulation should be modeled. I have performed this analysis based on an approach using the following steps:

1. First, I calculated the change in power price per dollar change in carbon price by taking the difference between around-the-clock ("ATC") power prices for 2023 IRP price scenarios with low carbon prices and mid carbon

[13] Deposition of Shawn E. Lange in File No. EA-2023-0286, p. 136, ll. 19-24.

prices and dividing that by the difference in carbon price for each year of the planning horizon (through 2043).

2. I then applied the change in power price per dollar change in carbon price determined in step 1 to the low carbon prices for each year to calculate the impact on ATC prices of the low carbon price scenario.
3. I then calculated the carbon price per MWh to apply to Rush Island by applying the carbon dioxide emission rate for Rush Island to the carbon prices for the low carbon price scenario.
4. I then calculated a margin impact per MWh for Rush Island by subtracting the power price impact of low carbon prices determined in step 2 from the carbon price per MWh determined in step 3.
5. I then applied the margin impact per MWh determined in step 4 to the change in Rush Island generation between the 2024 retirement case and the 2039 retirement case.

I made these calculations for each year from 2025 through 2039, then calculated the present value of the changes in margin. The impact of this approach is to remove any impact of carbon regulation on RIEC's margin, producing an analysis of whether to retire or retrofit RIEC unimpacted by either our approach of using carbon pricing assumptions or whatever alternative approach Staff might specify.

Q. What were the results of these calculations?

A. Removing carbon pricing from the low carbon price scenario results presented in my surrebuttal testimony would reduce the net present value revenue requirement advantage for 2024 retirement of RIEC compared to retrofitting with FGD and operating through 2039 by only about $61 million in current dollars. The approximate results with no carbon price would be $61 million lower than those shown for the low carbon price scenario in Table 3 in my surrebuttal testimony. The lowest advantage for RIEC retirement in 2024 compared to adding FGD to RIEC and operating through 2030 would still be very large, $914 million ($975 million - $61 million).

Q. Could that same $61 million reduction be applied to the results of the analysis you presented on pages 42-43 of your surrebuttal testimony (i.e., your analysis of adding FGD at RIEC in 2012 and operating through 2039 vs. retiring RIEC in 2024)?

A. No. I have performed a similar analysis that accounts for two important differences. First, the results presented for the analysis on pages 42-43 of my surrebuttal testimony are based on probability-weighted-average ("PWA") results for each case and thus reflect the PWA carbon price. Second, the analysis results are shown in dollars discounted to 2012 instead of today's dollars. The appropriate adjustment to results to reflect no carbon price at all is $86 million. The smallest advantage I determined for retiring RIEC in 2024 compared to adding FGD in 2012 and operating RIEC through 2039 was $531 million. That advantage for retiring RIEC in 2024 would still be several hundred million dollars, $445 million instead of $531 million. Again, that is the *lowest* advantage for RIEC retirement in 2024, and it assumes no form of carbon regulation at all, which is an extremely unrealistic assumption given where the push for climate policy clearly is today and where it is headed.

IV. OTHER CONCERNS EXPRESSED BY STAFF ARE WITHOUT MERIT

Q. In addition to Staff's concerns regarding the Company's assumptions for carbon pricing, Ms. Eubanks raises two new disagreements with the Company's direct case analysis of RIEC. What are those disagreements?

A. Ms. Eubanks says:

1. That the Company did not provide sufficient background on its assumptions or supporting work papers for the retire vs. retrofit analysis the Company performed in December 2021.[14]
2. That the Company should have accounted for MISO's new seasonal capacity construct when making the decision to retire RIEC.[15]

Q. How do you respond to the issues listed in item 2 in the above list?

A. While neither Mr. Fortson nor Ms. Eubanks claimed that my direct case RIEC analysis was flawed for not accounting for the MISO seasonal construct – this is a criticism lodged for the first time in Ms. Eubanks' surrebuttal testimony – they did claim that we had not planned as well as we should have. In the course of rebutting that contention in my surrebuttal testimony, I addressed the MISO seasonal construct and how it was considered in our planning in my surrebuttal testimony. Consequently, I have addressed these issues fully in my surrebuttal testimony and refer the Commission to that discussion. See my surrebuttal testimony, at page 18, line 4 through page 19, line 4.

Q. What is your response to item 1 above?

A. Frankly, I find this alleged issue to be frustrating to say the least. My direct testimony clearly indicates that the Company relied on the assumptions and modeling used

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[14] File No. EF-2024-0021, Claire Eubanks Surrebuttal Testimony, p. 2, ll. 3-5.
[15] File No. EF-2024-0021, Claire Eubanks Surrebuttal Testimony, p. 4, ll.6-8.

for its 2020 IRP as a starting point for the retire vs. retrofit analysis presented in that testimony. The entirety of the 2020 IRP filing and the associated work papers, to which Staff and other parties have had access for over three years, provide an extremely thorough and comprehensive set of information describing the analysis and assumptions on which that IRP filing was based, and the Commission found the Company's 2020 IRP to be in compliance with its IRP rules. Ms. Eubanks even acknowledges that the Company's IRP work papers were already available to Staff and other stakeholders in citing the Company's response to a Sierra Club data request[16] in the Company's 2022 electric rate case.[17] I also provided the workpaper supporting the additional analysis performed and used by Ameren Missouri management to make the RIEC retirement decision with my direct testimony in that electric rate case and again with my direct testimony in this case. As best as I can determine, the Company received no inquiries or formal data requests regarding that analysis in either case despite it having been available for over 18 months and despite the eleventh-hour interest in it.

To be clear, this issue in isolation might not be so frustrating if it were not consistent with a pattern of behavior on the part of Staff in recent years in which information is provided, months or years pass, and then Staff, having never raised an issue with the information or analysis during all that time, suddenly finds fault with it. For example, Staff indicated a need (and the Commission agreed) for an analysis of customer and shareholder risks associated with the Company's planned transition of its fleet to one that includes a large buildout of renewable resources over the planning horizon to mitigate numerous

[16] Sierra Club data request 1.12 in File ER-2022-0337.
[17] File No. EF-2024-0021, Claire Eubanks Surrebuttal Testimony, p. 2, ll. 4-5 and footnote 1.

transition related risks.[18] The Company filed this analysis in December 2021, meeting with Staff in advance of the filing to solicit feedback that might need to be incorporated. Staff indicated no issues with the analysis at the time and offered no suggestions for improvement. The Company subsequently included a more robust consideration of transition risks when preparing its revised preferred plan, filed in June 2022, with the help of experts with Roland Berger. The Company presented the results shortly after filing the notice of change in preferred plan with the Commission. Once again, Staff indicated no concerns with the analysis or conclusions presented by the Company and offered no suggestions for improvement. When the Company sought CCNs for four solar projects in 2023, Staff witnesses raised the same generalized concern about risks to customers from the buildout of renewable resources as though the Company never performed such an analysis at all.

This issue becomes even more concerning given Staff's apparent hostility to the IRP process in general, characterizing it as little more than an academic exercise and useless for the purpose of guiding utility resource decisions and Commission consideration of those decisions. This in spite of the Commission's very clear emphasis on the importance of the IRP process in the rules it adopted. It appears that there is a very serious misalignment between the Commission and its Staff regarding the importance of the IRP process in ensuring that electric utilities "provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy

[18] File No. EO-2021-0021, Order issued August 18, 2021.

and environmental policies."[19] I am not sure what can or needs to be done to address this misalignment, but it is clear to me that it needs to be addressed.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes, it does.

[19] 20 CSR 4240-22.010(2).

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Petition of Union Electric Company d/b/a Ameren Missouri for a Financing Order Authorizing the Issue of Securitized Utility Tariff Bonds for Energy Transition Costs related to Rush Island Energy Center.	))))))	EF-2024-0021

AFFIDAVIT OF MATT MICHELS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Matt Michels, being first duly sworn on his oath, states:

My name is Matt Michels, and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Sur-Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Matt Michels
Matt Michels

Sworn to me this 3rd day of April 2024.

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1. Introduction

Ameren Missouri retained Charles River Associates (CRA) to support Ameren Missouri for the 2023 Integrated Resource Plan (IRP) filing. CRA is a leading global consulting firm that offers economic, financial, and business management consulting expertise and applies advanced analytic techniques and in-depth industry knowledge to complex engagements for a broad range of clients.

The energy practice of CRA has staff located in Washington DC, Boston, London, and Toronto. CRA advises a range of clients on a range of issues including resource planning, asset valuation, auction design and implementation, policy development, and procurement and planning strategies. Recently CRA has supported numerous investor- and publicly-owned utilities to develop long-term generation, transmission and distribution plans that meet the evolving needs of customers, regulators, and other stakeholders.

In this report, we provide the results for three specific workstreams that were part of the scope of work developed for Ameren in late 2022. More specifically:

- Section 2 includes an assessment of the reasonableness of the load forecast, carbon price forecast, and natural gas price forecast assumptions used by Ameren Missouri in the upcoming IRP.
- Section 3 includes analysis regarding the need for ancillary services price development for this IRP and;
- Section 4 includes commentary on the energy and capacity prices results determined by CRA's modeling effort.

2. CRA Objectives and Framework for the IRP Input Audit

CRA performed a comprehensive review that examined all aspects of the IRP input analysis including the applied methodology, sources, and justification of the final projections. To accomplish this review, CRA formed a team of subject matter experts that have supported IRP analyses throughout North America and have been involved in the development of inputs for various IRPs.

Additional support and consultation was provided throughout each step of the process by members of Ameren's Corporate Analysis team to ensure accurate understanding of Ameren's process by the CRA team.

During the pre-work for this effort, Ameren shared with CRA three critical objectives for the IRP Input review effort:

- Provide clarity around the entire IRP input development process for internal and external stakeholders.
- Verify the reasonableness of the key inputs needed for modeling and determine whether the current process produces an adequate range of each variable that captures most expected outcomes.
- Identify appropriate and efficient resolutions for any identified gaps in the development of the key inputs.

In order to conduct a full examination of the multitude of inputs used in the IRP process, CRA reviewed all aspects of these inputs, including cross-verification against source materials and evaluation of internal methodologies and processes for developing Ameren-specific data (e.g., the company load forecast).

Specifically, CRA evaluated the reasonableness of Ameren’s load, natural gas price, and carbon price assumptions, comparing the company’s input development and results to:

1. Industry accepted data sources and forecast development approaches.
2. Acceptable historic performance of the data sources.

The review of peer companies and their forecast development approaches provide a reasonable basis for Ameren’s forecasting methods. Widely accepted approaches that have been in place for multiple IRPs indicate their robustness and reasonableness. Similarly, acceptable historic performance of the data sources enhances confidence in the assumptions and the eventual results of the portfolio development.

2.1. IRP Input Audit Findings Summary

CRA’s review spanned a three-week period, and involved interviews with Ameren staff, review of documentation provided by the Company, and review of industry best practices and other utility assumptions. The recommendations can be summarized as follows:

IRP input development process:

- Overall, CRA recommends the development of a documented process for the IRP input to ensure consistency between IRPs. Changes driven by staff turnover, methodology updates and other can be mitigated by a well- documented process.

Natural Gas Price:

- Continue the consideration of the Henry Hub pricing point as the basis for the development of natural gas base/high/low outlooks. Henry Hub is commonly used by peers and represents a reasonable reflection of natural gas market dynamics in North America.
- Based on CRA’s analysis, the proposed range of the Henry Hub prices appears to be reasonable. Given the recent market developments and the market expectation over the long run reflected in peer company projections, our analysis indicates a reasonable range of the expected curves. CRA recommends the continuation of the consideration of multiple third-party forecasts in the development of the Company’s natural gas price assumptions to better reflect expected natural gas market fundamentals.
- Continue to incorporate internal subject matter experts’ views on price curves obtained from publicly available sources, private services, and current market pricing. The natural gas market is continuously shifting; therefore, the incorporation of expert views can better align less recently developed forecasts with newer market developments.

Carbon Price

- Continue to incorporate a carbon price in the regional forecast to reflect recent industry trends. Based on CRA’s review, it is appropriate for Ameren to evaluate the impact of a federal carbon price program or other explicit or implicit carbon price mechanisms on resource planning.
- It is still unclear how the newly passed Inflation Reduction act will affect the need for a future carbon pricing program. The IRA is mostly focused on accelerating the integration of clean energy technology, while the carbon price seeks to limit fossil generation. Therefore, it is difficult to correlate the impact of the two without further studies.

- CRA's review of peer companies and CRA's internal analysis confirms the reasonableness of Ameren's proposed high, base and low carbon price projections.

Load Forecast

- Align with peer companies that include ISO/RTO load forecasts in their IRP regional load forecasts. Various companies consider their native ISO/RTO load that could reflect regional load dynamics more precisely than EIA's AEO projections. For Ameren, it is reasonable to use as the market IRP input the load forecast developed for the Midcontinent Independent System Operator (MISO), since it provides an independent view that is more in alignment with the ISO/RTO planning processes than the EIA load projections.
- CRA recommends Ameren incorporate the high and low MISO load growth cases for regional load. These load forecasts have been developed by an independent party considering different demand side management, electrification, and distributed generation penetration.

2.2. Natural Gas Price Forecast Audit

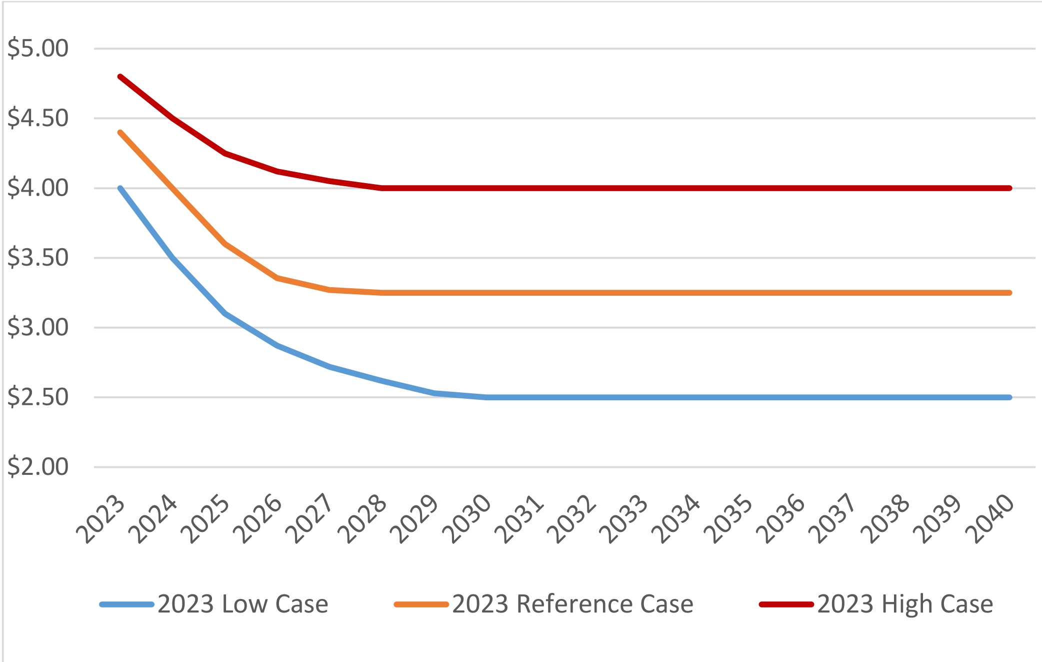
Natural gas prices continue to have a very strong influence on energy prices. The company employs a forecasting method for natural gas prices based on a hybrid approach that considers third party forecasts, the latest projections from the Energy Information Agency Annual Energy Outlook and Ameren's natural gas experts' views. For this IRP, Ameren used multiple views from the recent EIA AEO 2022 for Henry Hub, a current third-party forecast from Platts, and natural gas market intelligence collected by Ameren's gas market experts.

Specifically, Ameren's internal experts considered a range of drivers for the 2023 IRP including the following:

- Impacts to natural gas supply due to the Russian invasion of Ukraine
- Natural gas infrastructure challenges related to greenhouse gas and environmental/legal considerations
- Hydrocarbon production disruptions reflected in investments of new production

Based upon these inputs Ameren developed assumptions for three price curves – base, high and low – for future prices for natural gas that are represented by the price levels depicted below:

Exhibit 1 Henry Hub ($2023/Dth)



Following the audit methodology described in the introduction of this section, CRA reviewed widely accepted industry practices to compare the reasonableness of the forecasting approach utilized by Ameren.

First, CRA collected information related to the methods used for the development of the natural gas price projections from several peer companies' IRPs. Although applied in slightly different manners, CRA's research identified three generic approaches used by utilities to develop regional natural gas price forecasts:

The first method relies on a combination of multiple third-party consultants as well as current trading sources, such as NYMEX for the development of the different price outlooks with appropriate internal adjustment. This method was used by Entergy Arkansas, LLC which considered multiple independent, third party-consultants for its long-term forecast.[1] Vectren (Southern Indiana Gas and Electric Company) averaged forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, and EVA.[2] Third party forecasts capture the most recent market dynamics, but their vintage can be an issue, since they may not have been developed during a timeframe that fully reflects current and expected market dynamics. This drawback is usually mitigated by adjustments on the forecast by internal natural gas market experts. Ameren's approach considers multiple sources while also considering current and expected market dynamics, thus avoiding the need for secondary adjustments to averages of third party forecasts.

The second method applies a standardized probability-weighed approach on external independent sources with very minimal internal expert view modifications. Evergy Metro, Inc.

[1] Entergy IRP, 2021 Integrated Resource Plan

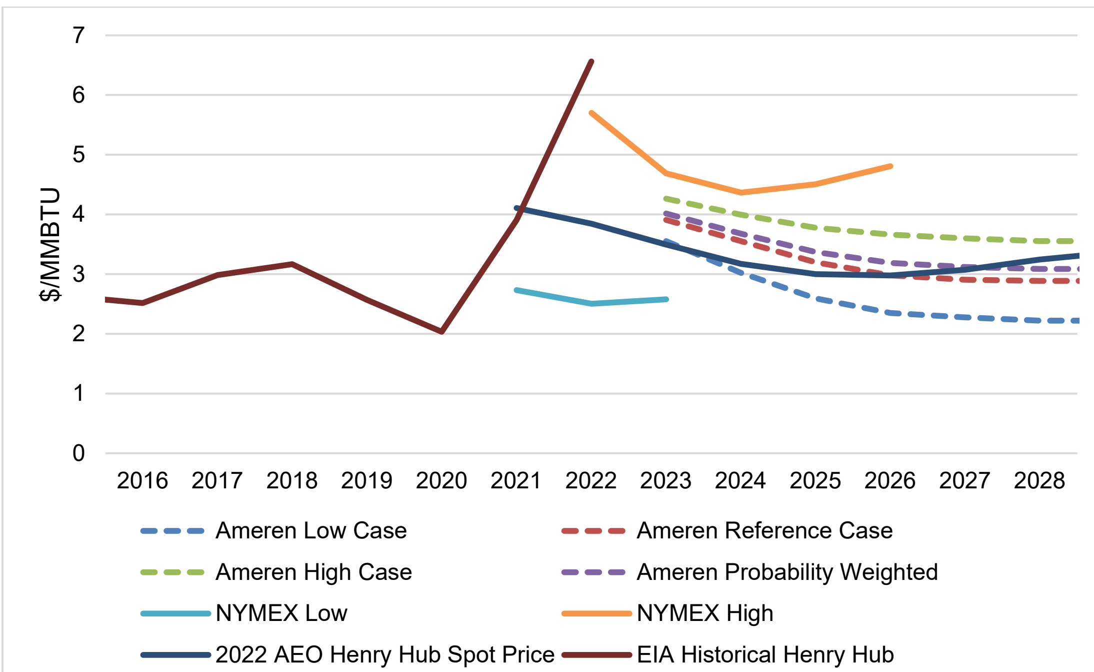
[2] Vectren 2019-2020 IRP

subscribed to this approach by combining external source forecasts in equal weight. These forecasts were from IHS Markit, Energy Information Administration, S&P Global Platts, Energy Ventures Analysis, and CME Futures. Similar to the previous approach, it can be challenging to align the results of different vintage forecasts. Also, the limited internal adjustment may exclude more recent market dynamics. The multiple third parties forecast approach limits the risk of "anchoring" the forecast on one view.

The third approach relies on a bottom-up forecast of North American gas production and prices using a fundamentals-driven natural gas model. The model develops natural gas price outlooks under different supply, demand, infrastructure investment levels. In the near term, this method considers current market forward strips and slowly incorporates the fundamental view beyond the near term. CRA has utilized this approach for various IRP efforts in North America. However, doing so can add cost and complexity to the consideration of price assumptions by internal experts.

Exhibit 2 compares Ameren's preliminary forecast with the AEO EIA's reference case and the recent NYMEX high and low prices taken from separate time frames. Overall, Ameren's projections are aligned with the EIA AEO view over the near to mid-term. Since the 2022 AEO prices did not capture the most recent price spike, it is appropriate to reflect this recent market development in the near term by using recent forward strips and natural gas market expert's input.

Exhibit 2 Ameren's Reference Natural Gas Forecast compared with the 2022 Forecast ($2022)[3]



In terms of the forecasting approach, CRA finds Ameren's approach reasonable. The consideration of multiple sources along with internal market knowledge provides an appropriate view of the natural gas market prices projections. The method ensures

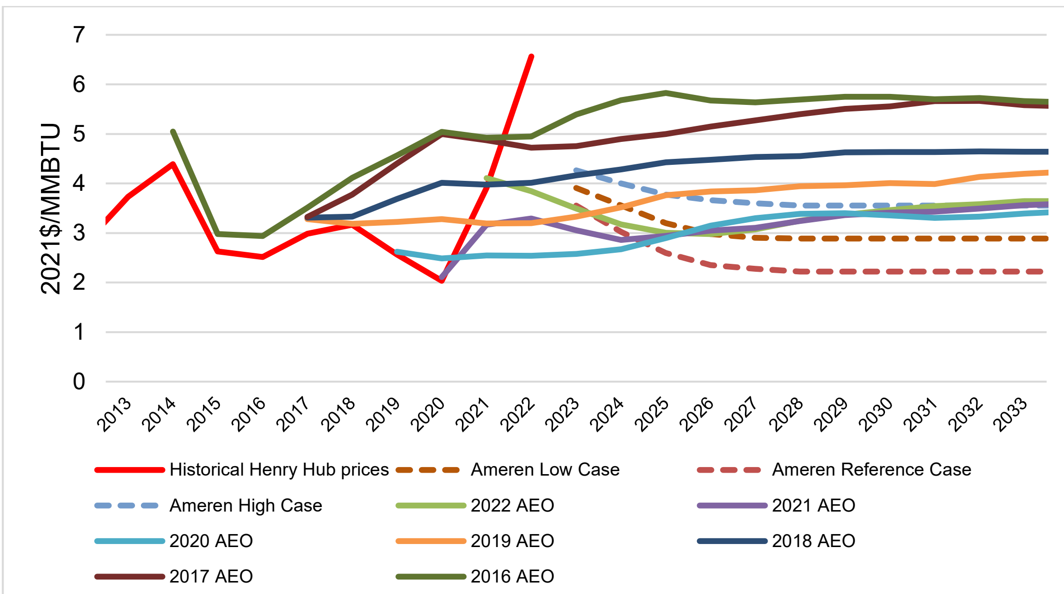
3 Low Case Based on Low Range April 2021 NYMEX trading, Reference Case based on average of Platt's and EIA AEO averages, High Case based on High Range July 2022 NYMEX trading

independency by the inclusion of third-party views and better reflection of current market dynamics provided from experts' views.

As mentioned above, Ameren uses EIA and various third-party forecasts for the development of its future gas price estimates. Since CRA has no access to the historical third-party data and is thus unable to compare their performance against actual results, the audit concentrated on the comparison of the AEO EIA reference case with actual historical prices.

Exhibit 3 provides the AEO EIA projections for the Henry Hub under different vintages and compares them with actual prices. Overall, the AEO reference case tends to over-estimate the price for gas, as identified by the separation between the actual prices and the different projections. As expected, the forecast error decreases when closer to the actual pricing. However, the forecast error always appears to be on the high side.

Exhibit 3 Comparisons of natural gas prices between AEO Annual forecasts and Ameren's 2023 IRP prices

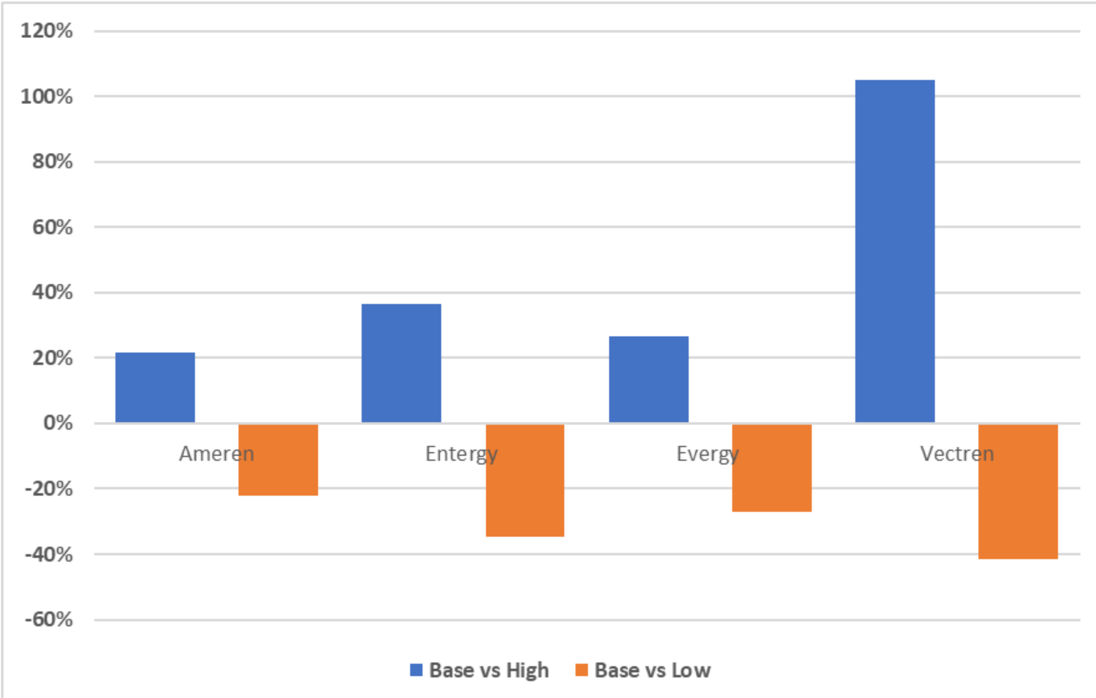


Based on this assessment, it is reasonable for Ameren to establish its base and boundary price projections slightly below the AEO's reference case projection. The historical over-estimation compared to actuals provides a reasonable justification for this result.

Furthermore, to assess in more detail Ameren's base and boundary conditions, CRA reviewed peer company projections for low and high and their ranges compared to base. Although the information reviewed does not align with the timing of this IRP – and as result does not capture most of the latest market developments – it provides a reasonable benchmark on whether the base and boundary conditions proposed by Ameren are reasonable. The exhibit below compares in CAGR terms the difference between base and low and base and high cases for three Ameren peers that developed their IRPs during a recent timeframe.

Exhibit 4 Ameren and peers natural gas range average % difference for base vs high and base vs low

Schedule MM-SS1



Note that Ameren's ranges are in line with Evergy's but shorter than Entergy and Vectren as Ameren's most recent price forecast includes a price spike related to the latest market developments in the natural gas market that may not have been fully incorporated into the Evergy and Vectren IRPs (due to the timing). All four IRPs stress the natural gas market on the high side more than the low end, which is appropriate given the planning risks of a prolonged high natural gas market price environment.

In conclusion, CRA finds Ameren's base, high and low projections for the natural gas prices reasonable. More specifically:

- Continue the consideration of the Henry Hub pricing point as the basis for the development of natural gas base/high/low outlooks. Henry Hub is commonly used by peers and represents a reasonable reflection of natural gas market dynamics in North America.
- Based on CRA's analysis, the proposed range of the Henry Hub prices appears to be reasonable. Given the recent market developments and the market expectation over the long run reflected in peer company projections, our analysis indicates a reasonable range of the expected curves. CRA recommends the continuation of the consideration of multiple third-party forecasts in its natural gas projections to better reflect expected natural gas market fundamentals.
- Continue to incorporate internal subject matter experts' views on price curves obtained from publicly available sources and current market pricing. The natural gas market is continuously shifting; therefore, the consideration of expert views is appropriate to reflect more recent changes affecting ranges of future prices.

2.3. Load Forecast Audit

Load estimation over the IRP time horizon is one of the IRP cornerstones. The long-term energy and demand forecast is usually separated into two processes. One determines the load forecast for the utility territory – usually used during the preferred portfolio determination. The second focuses on the estimation of the regional load forecast required to establish regional market scenarios that will be used to test the performance of various developed portfolios. In this effort CRA audited Ameren's regional load determination process and projected views.

Ameren develops three regional load growth scenarios that represent different economic projections and expert views on energy efficiency, distributed generation, and electrification. The Energy Information Administration's West North Central Case for the Eastern Interconnect is utilized as a basis of the forecast adjusted for the high and low cases according to input from Moody's Economic Outlook and impacts from the factors mentioned above.

To evaluate the reasonableness of Ameren's regional forecast process and projected views, CRA relied on reviewing the processes of Ameren's peers and assessing the reasonableness of Ameren's sources and historic performance.

There is limited information in produced IRPs on the development of the regional load forecast. The IRP documents include detailed information on the native load forecast development for each company but spend limited time on the effort for the development of the regional load used for the fundamental analysis. Since utilities have a limited impact to the regional load trends, they usually rely on commonly accepted publicly available sources with a historically consistent forecasting methodology.

CRA reviewed various IRPs to identify different approaches for the forecast of regional load The most common methods are the following:

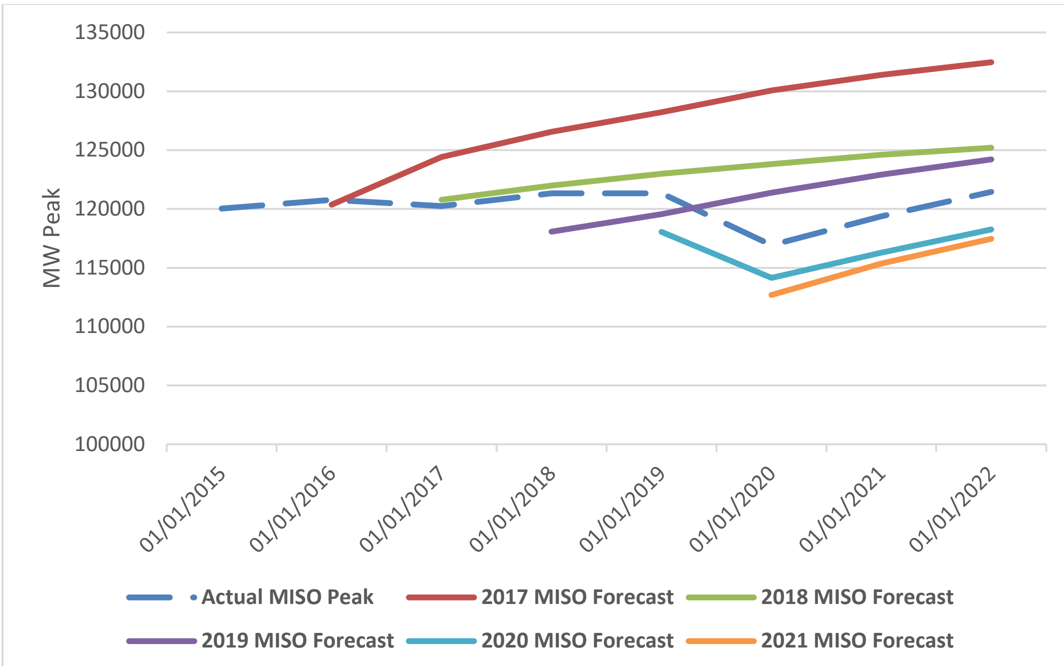
- Utility developed regional load; For example, Indiana Michigan Power incorporates AEP's (parent company) load forecast for the base and alternative scenarios. The IRP documentation provides no additional details on how these forecasts were developed.
- RTO/ISO produced load; PJM, MISO and other ISO/RTOs develop regional forecasts for energy and demand on an annual basis. The forecast incorporates input from load serving entities within their jurisdiction. For example, Vectren utilizes the demand forecast provided by the MISO market in the System Forecasting for Energy Planning Section of MISO's website. The alternative load forecast scenarios are a variation of the base MISO load forecast that incorporates analysis from Vectren staff. CRA's regional load forecast approach relies on this method that has been used for various client engagements within organized markets.
- AEO EIA load forecasts; Various utilities including Ameren rely on the annual regional load forecast updates provided by EIA. These forecasts are heavily influenced by economic factors such as Gross Domestic Product and provide a reasonable source for the regional IRP load forecast development.

The RTO/ISO forecasts are developed by an independent entity under rigorous scrutiny by stakeholders. Although EIA AEO's forecasts are reasonable, the RTO/ISO projections provide a "closer view" to a specific region in the US. The ISO/RTO forecasts also incorporate input from stakeholders – usually utilities – that reflects more accurate trends than a nationwide forecast.

For the historic performance evaluation, CRA's review relied on two comparisons. The first compared MISO's historical load projections with actuals, and the second compared EIA's projections with actuals.

First, CRA compared the forecast developed by Purdue University for the MISO process. We collected the load forecast for five MISO Energy and Peak Demand Forecast reports and compared them the actual peaks realized by the ISO. The exhibit below depicts this comparison. Notably, the projections both overestimate and underestimate the actual regional forecast but remain in a tight band, especially in the near term.

Exhibit 5 MISO Forecast compared to actual Summer Peak



Second, CRA compared EIA's AEO projections for the reference case for the past 8 years with the actual demand for the states within the West North Central Region. The table below compares the expected annual average growth from each AEO and the total load year over year consumption growth for of the states that comprise the region.

	EIA AEO West North Central average expected growth – Reference Case	Year over Year Actual load growth consumption
2014	0.54%	1.2%
2015	0.55%	-2.1%
2016	0.49%	0.1%
2017	0.56%	0.1%
2018	0.48%	4.3%
2019	0.48%	-1.8%
2020	0.54%	-2.3%

2021	0.66%	3.5%
Average	0.54%	0.38%

Overall, the West North Central estimates by EIA capture the year over year expected base growth for the region. However, they appear to slightly overestimate the expected load growth for the region.

In conclusion, CRA finds reasonable the consideration of EIA AEO's West North Central case as the basis for the regional load forecast used in Ameren's IRP. However, CRA recommends adopting the MISO load forecast for the following reasons:

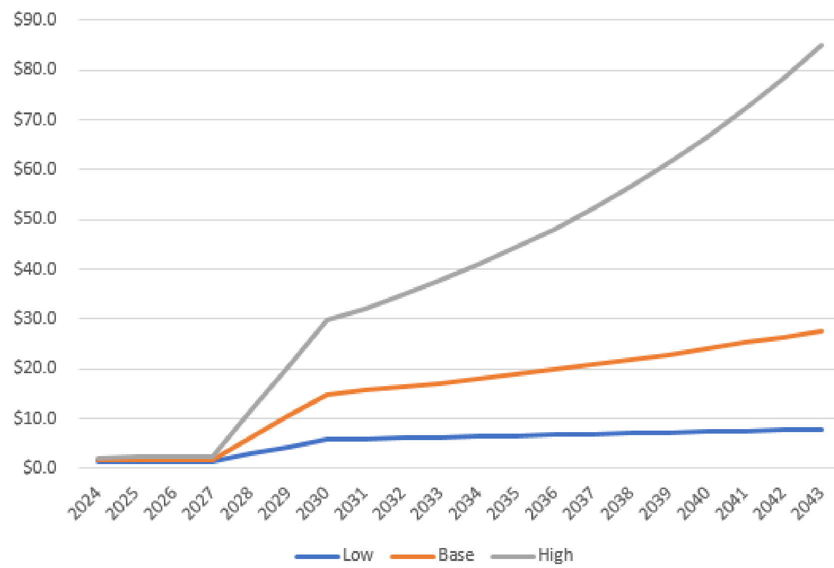
- The ISO load forecast reflects a view of energy consumption that more closely matches regional performance and expectations than EIA's forecasts, since it is developed by the ISO after incorporating input and feedback provided by member utilities.
- The MISO load forecast appears to be more commonly used by utilities in MISO. A more widely accepted approach can be better understood by regulators and stakeholders and ensures better consistency of assumptions.

2.4. Carbon Price Forecast Audit

Although several legislative and executive actions related to Greenhouse Gas Emissions (GHG) have been attempted over the last decade, there is currently no federal carbon pricing program and no binding power sector GHG emission limits at the federal level. However, given multi-faceted efforts by the Biden Administration and Congress to reduce GHG emissions, CRA concurs that Ameren's IRP modeling should include a carbon price to reflect the impact of such policy on planning.

Similar to the development of the natural gas price and regional load forecasts, Ameren developed a range of carbon price assumptions to reflect different potential policy regimes. Based on CRA's discussion with the Ameren staff, the three cases (base, high and low) were informed by detailed research with the objective to capture a wide spectrum of outcomes using input from databases and other utilities' projections. The exhibit below depicts Ameren's proposed base, low and high cases.

Exhibit 6 CO2 Price Forecast ($2022/MT) for Base, High and Low cases

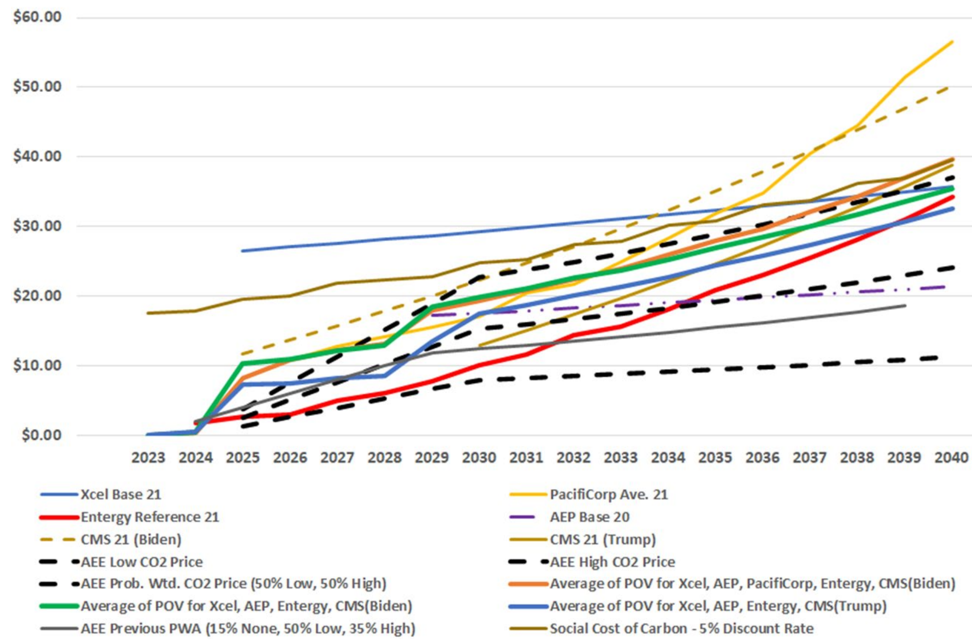


Ameren considered various drivers that affect the timing and level of carbon pricing such as the need for a potential program that considers carbon pricing through legislation (e.g., Carbon Tax, Cap-and-trade Program, Clean Energy Standard), RTO markets, and other mechanisms. Ameren also considered recent price forecasts developed by peer companies such as Xcel, AEP, Entergy and others.

Since there is no established federal program for carbon price, a comparison with peer company approaches is limited to the motivation for the application of carbon price (level and timing) and the sources considered to justify the developed price projections. Moreover, the choice for a specific level and timing was also driven by the considered scenario theme the IRP was seeking to capture. For example, a scenario that modeled a view of increased regulatory pressure on carbon and stricter GHG goals incorporated a higher price for federal carbon than a scenario that modeled a view with moderate to low regulatory intervention.

The exhibit below depicts the various price projections of available sources.

Exhibit 7 CO^2 Price comparisons from various utility sources (2021 Nominal$/Metric Ton)



Comparing Ameren's projections to the rest of the sources, it appears that the company captures a reasonable spectrum of potential outcomes. The base case tracks most of the peer utility projections, while the high case reflects more aggressive carbon emission reduction studies (CMS). If a carbon price increases to the $80-90/ton range (in real 2021$) it could make certain alternative technologies required to achieve net zero emissions by the 2035-2040 timeframe (such as hydrogen, CCS, and nuclear) economically feasible. On the low end, Ameren's forecast considers a non-zero price for the carbon program that will commence around the same time as the base and high cases. It is appropriate to have an outcome where the carbon program will not have a significant impact to the planning decisions since there is a potential for futures in which state and/or federal legislators and/or regulators may not be as aggressive on carbon reduction.

Based on CRA's analysis and discussion with the Ameren staff, it was confirmed that the latest passage of the Inflation Reduction Act was not expected to alter the range of carbon price curves. Even though IRA is expected to have a positive effect on the development of renewables, it is difficult to determine whether a carbon program will still exist regardless of the IRA. However, a range of potential policy regimes that reflect some degree of explicit or implicit carbon pricing remains a possibility.

In conclusion:

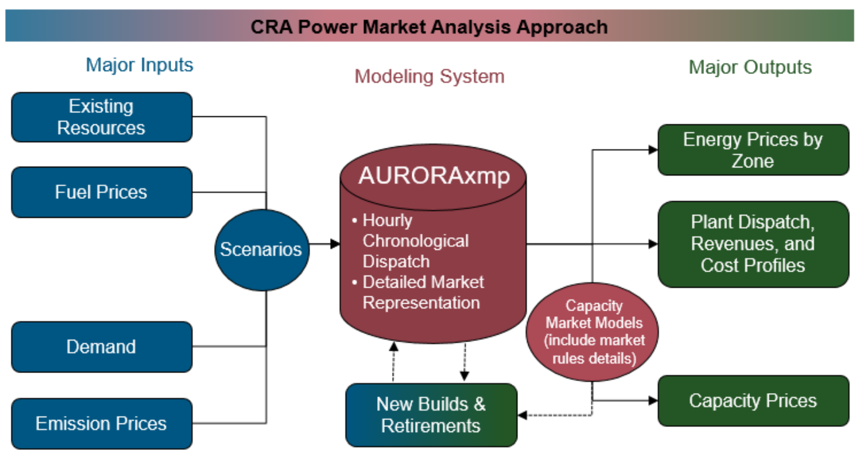
- Continue to incorporate a carbon price in the regional forecast to reflect recent industry trends. Based on CRA's review, it is appropriate for Ameren to evaluate the impact of carbon prices, whether explicit or implicit, on resource planning.
- CRA's review of peer companies and CRA's internal analysis confirms the reasonableness of Ameren's proposed high, base and low federal carbon price projections.

3. Planning Scenarios Price Development

CRA developed various MISO market scenarios that test plausible but materially different long-term views of fundamental external market conditions such as natural gas prices, carbon prices and energy consumption. These eleven scenarios were used to inform the creation of candidate portfolios of demand- and supply-side resources.

Each of these market scenarios is supported by a set of assumptions describing the fundamental inputs from the Ameren IRP Input process that was audited by CRA. The key categories of assumptions used to develop the 2023 IRP market scenarios include: load, natural gas prices and CO_2 prices. All eleven scenarios in the 2023 IRP were modeled using AURORA to evaluate the evolution of generation capacity and prices across MISO under these different sets of fundamental conditions. This process is illustrated in Figure 1.

Figure 1: 2021 IRP Modeling Framework



3.1. Price Scenarios Development

The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. The Aurora model iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and other.

The AURORA model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities, and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the AURORA model.

CRA evaluated eleven market scenarios that describe plausible futures that may develop over time and result in a materially different set of market conditions under which Ameren will need to serve customer needs. Each scenario is developed by a combination of three critical variables: load, natural gas prices and carbon prices. The cases are labeled as follows:

Schedule MM-SS1

Case	Load	NG	CO2
1	Base	Base	Base
2	Base	Base	Low
3	Base	Base	High
4	Base	Low	Base
5	Base	Low	Low
6	Base	Low	High
7	Base	High	Base
8	Base	High	Low
9	Base	High	High
10	High	Base	Base
11	Low	Base	Base

3.2. Scenario Assumptions

For the development of the eleven cases, CRA used three different projections each for regional load, natural gas prices and carbon prices.

MISO Load Growth

Load growth is a critical driver of wholesale energy and capacity prices. CRA utilized the latest MISO estimates developed for the April 2021 MISO Futures report.

Under the Base Case, demand for energy in MISO is expected to grow by 0.7% per year over the 20-year forecast period (2023-2042) and 2.1% per year for the High case where load growth reflects increased economic growth, deployment of electric vehicles, and greater building electrification. For the Low case, the annual growth is -0.3% per year driven by lower economic growth and adoption of distributed technologies.

Peak summer demand is expected to grow at a rate of 0.7% per year for the Base case, and 2.2% for the High case. The Low case reflects a 0.4% decline in energy consumption per year over the study period. The details of the analysis and the assumptions underlying the load forecast are discussed in Section 2 above.

Exhibit 8 MISO Energy Load Projections for Base, High and Low cases

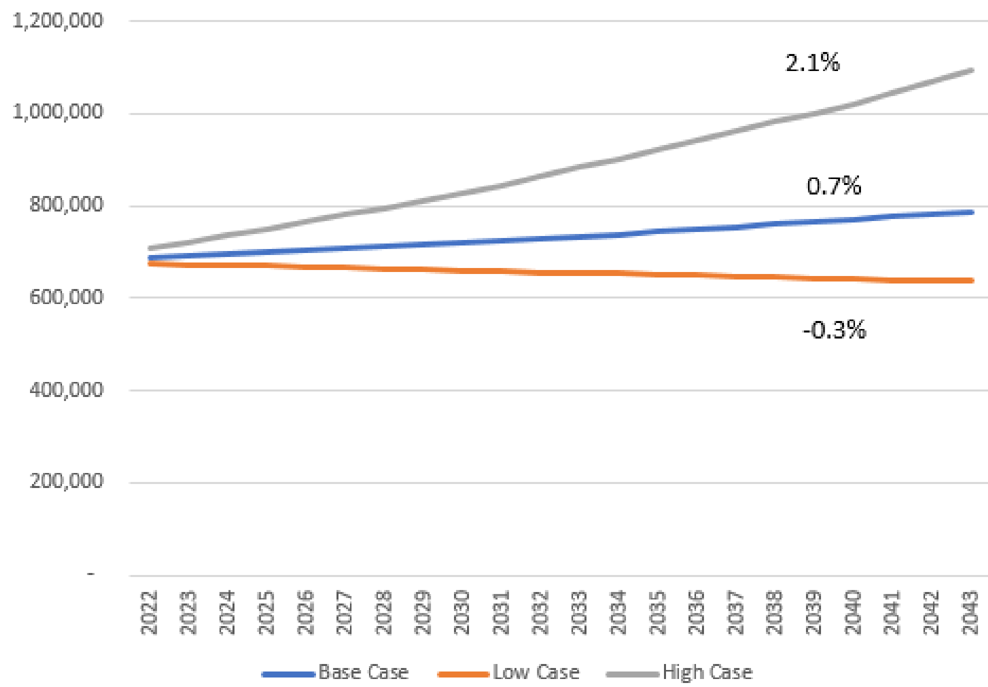
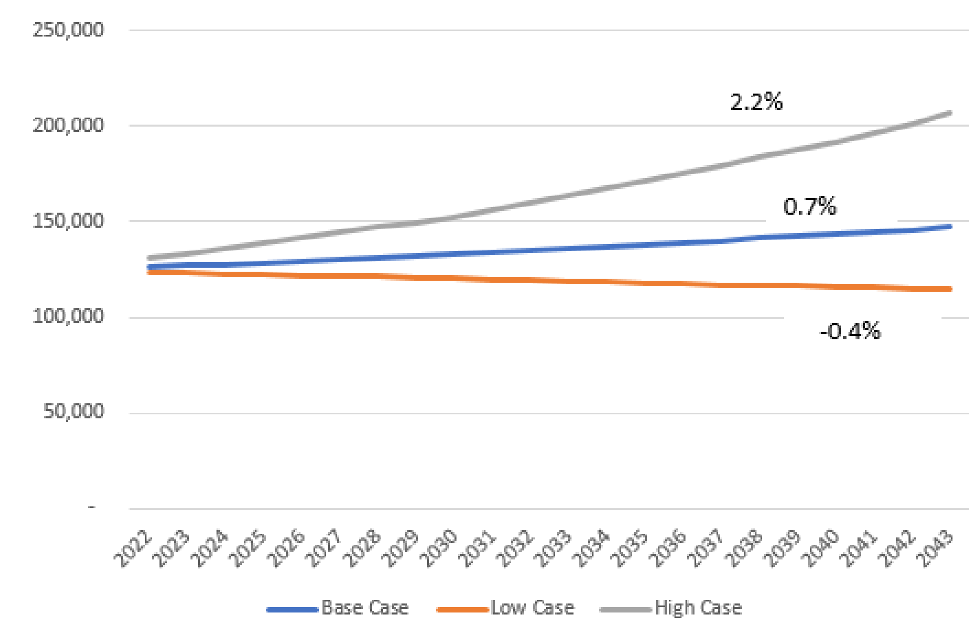


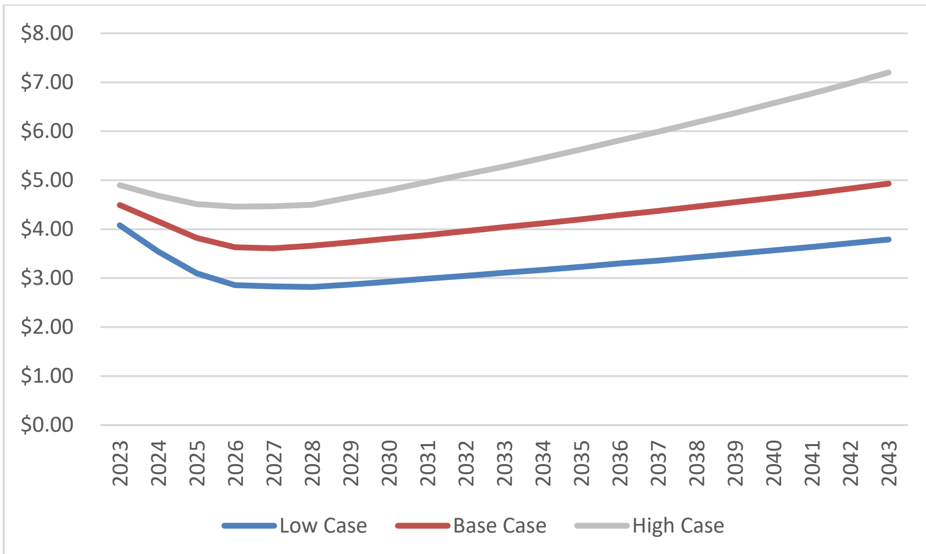
Exhibit 9 MISO Summer Peak load for Base, High and Low cases



Natural Gas Prices

Exhibit 10 illustrates the annual Henry Hub natural gas price forecast that was used for the MISO market modeling in the different cases. This pricing point was selected for the report because it reflects the most liquid pricing point for natural gas in North America. In all three cases, prices decline in the early years to reflect normalization of the market after the various supply and demand shocks related to the pandemic and geopolitical turbulence. In the base and low case, the prices remain flat in real terms – with the low case at lower levels than the base case. The high case depicts an outcome where natural gas prices do not decline as much reflecting reduced gas supply relative to demand over time.

Exhibit 10 Henry Hub Prices for Base High Low (nom $ / MMBtu)

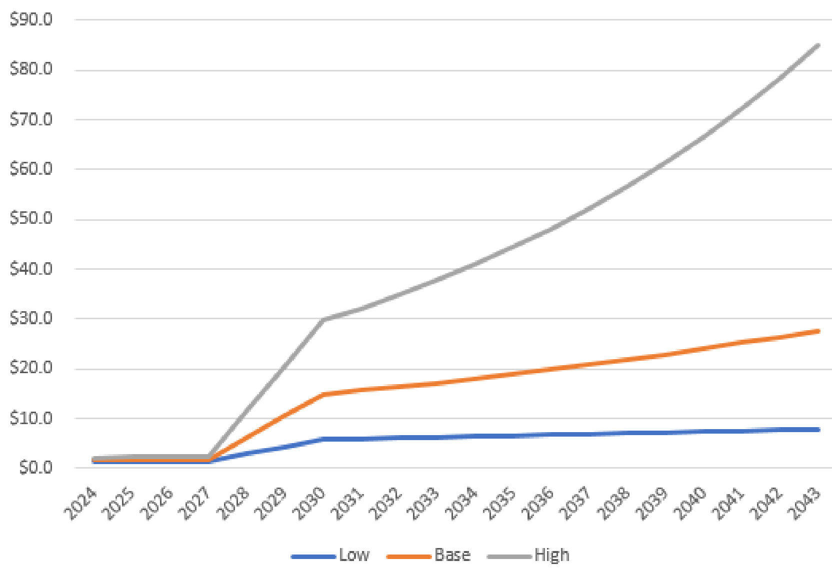


CO_2 Prices

Under the base case policymakers enact measures that put moderate pressure on the economy to reduce greenhouse gas emissions in the form of a carbon price starting in 2028. However, there is the potential that future emissions reduction policy could be more restrictive than expected and that the level of policy pressure could be materially higher, as represented in the high CO_2 price forecast used in the High Case. Under the low case scenario, policymakers enact minimal restrictions or economic disincentives on CO_2, and prices are assumed to be the lowest of the three outcomes throughout the forecast period.

The CO_2 price increases the dispatch cost of all fossil-fired units in MISO based on the modeled emissions of the unit that, in turn, is a function of each unit's heat rate and carbon content of the fuel it consumes.

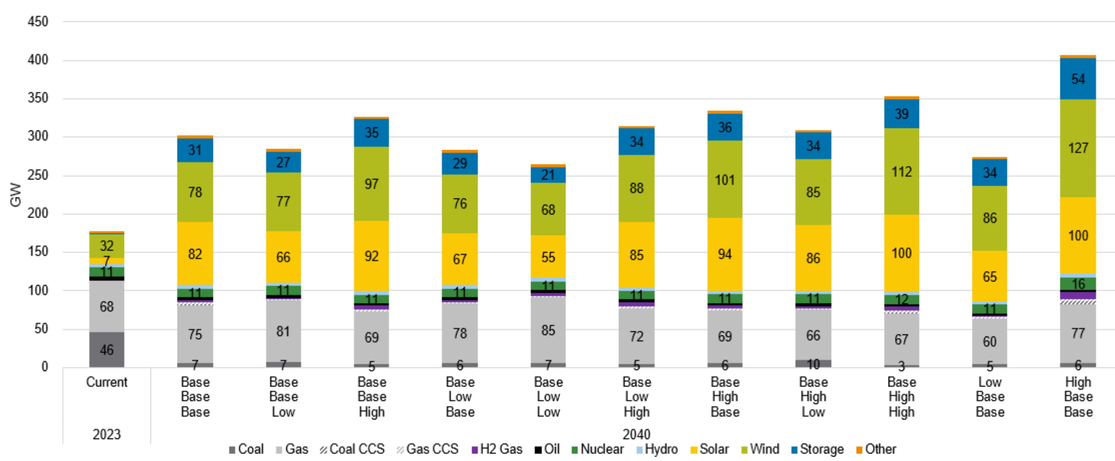
Exhibit 11 CO2 Price Forecast ($2022/MT) for Base, High and Low cases



3.3. Capacity Expansion Results

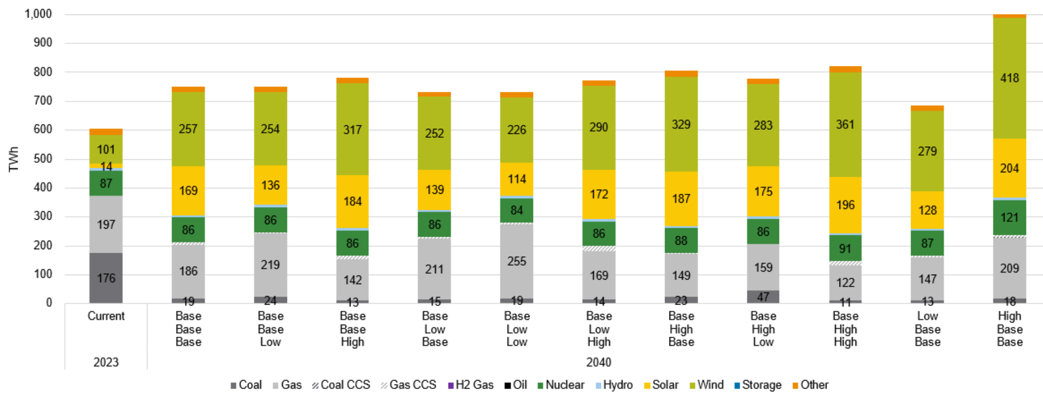
CRA used the AURORA LTCE model to forecast the least-cost combination of resource additions and retirements in MISO using the assumptions for each pricing scenario. Exhibits 12 and 13 below illustrate the 2042 capacity and generation mix (respectively) across all eleven market scenarios compared with the MISO resource mix in 2023.

Exhibit 12 Comparison of Nameplate Capacity by Technology in MISO between 2023 and 2042 for all 11 cases



Schedule MM-SS1

Exhibit 13 Comparison of Generation by Technology in MISO in 2042 with 2023 in Zone 5



The results that differentiated each case are:

Capacity and Generation

Future renewable entry was heavily influenced by the natural gas and carbon price inputs. Lower input prices tend to result in worse economics for renewable resources due to their nature as low-variable-cost price takers, while natural gas and coal resources are more likely to maintain their relative economics. In specific cases, the reverse occurs, where higher natural gas and carbon prices result in accommodative economic conditions for renewables, while certain less efficient natural gas and coal resources retire. Other fundamental drivers are the Inflation Reduction Act that incentivizes solar, wind, and storage entry through the realization of Production Tax Credits and Investment Tax Credits.

Overall, renewable entry directly affects the total amount of fossil-fuel capacity in the system since low variable cost resources drive traditional fossil fuel resources up the merit order making them uneconomic more frequently. Between coal and gas resources, higher gas prices tend to benefit coal generation that under those conditions remains in the market longer. Furthermore, high carbon price negatively affects the economics of coal resources, accelerating their retirement.

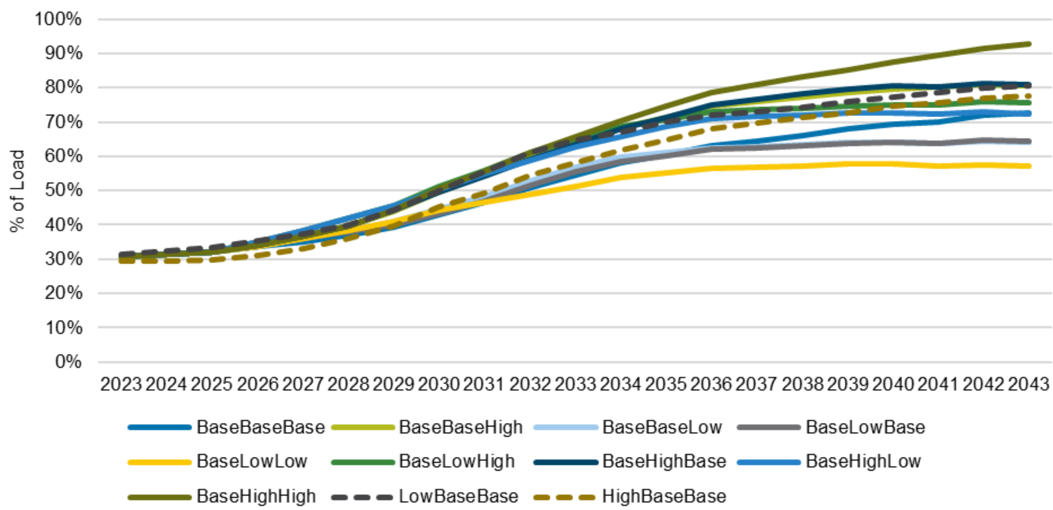
Within CRA's analytical framework, the level of natural gas and CO2 prices directly affect different levels of renewables penetration. Based on each case's assumed combination of natural gas and CO_2 prices, gas and coal resources react in a different manner. For example, in the high gas and low carbon price case, economics favor coal plants over natural gas, while in all high gas prices cases the model adds higher levels of renewables, which gradually replace existing fossil-fuel capacity.

CRA also considered other programs exogenous to the MISO market construct in this effort. For example, within Ameren's territory, CEJA's emission constraints accelerated retirements of several coal plants.

Clean Generation (% of Load) and Emissions

Clean generation as a % of load increases and emissions decline in all eleven cases. The BaseHighHigh case realizes the highest amount of clean generation as high carbon prices penalize fossil generation while high natural gas prices improve the economics of new renewable entry. On the opposite side of the spectrum, the BaseLowLow case maintains the highest amount of coal resources – due to the less punitive carbon prices – and the lowest amount of renewables – due to unfavorable economics from the assumed low gas prices.

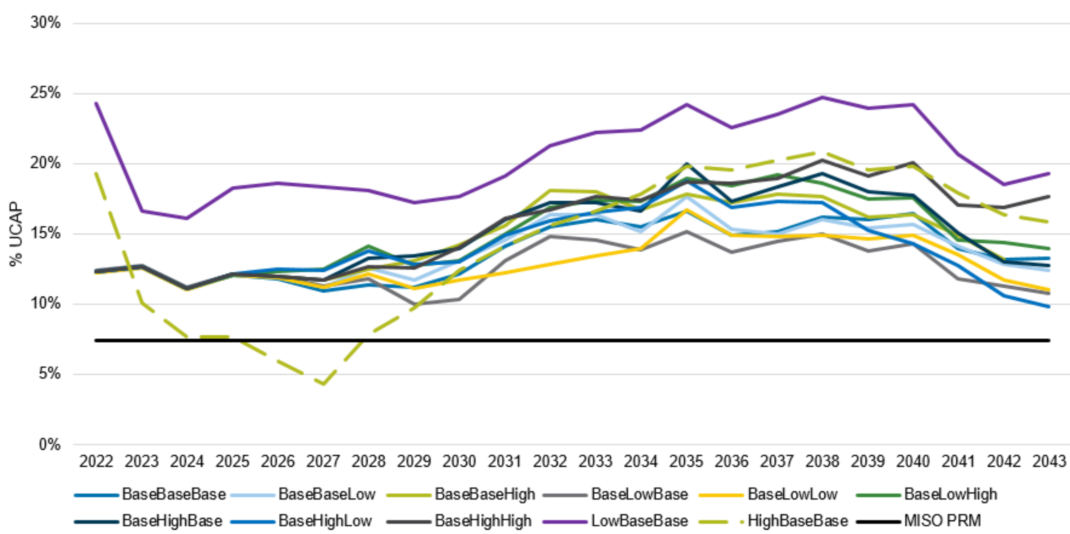
Exhibit 14 Clean Generation as % of MISO Load



Reserve Margins

Reserve margins alter based on produced capacity results for each case. In general, reserve margins are maintained above the MISO PRM (specifically 7.4% for summer and 25.5% for winter). The HighBaseBase Case is the only one that experiences a low RM in the short term due to the aggressive load growth and the slow replacement of exiting high peak credit capacity with renewables with lower accredited capacity value.

Exhibit 15 MISO Summer Reserve Margin for all cases

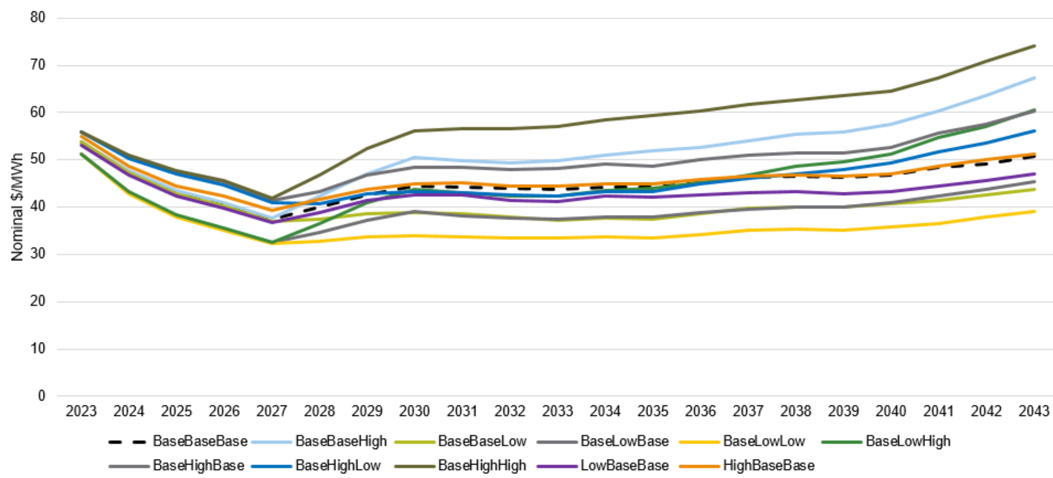


3.4. Energy Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Exhibit 16. Shown are all eleven market scenarios modeled as input to the 2023

Ameren IRP. The exhibit illustrates the wide but plausible range of energy prices that emerge from the scenario modeling that were used to develop and select the preferred plan.

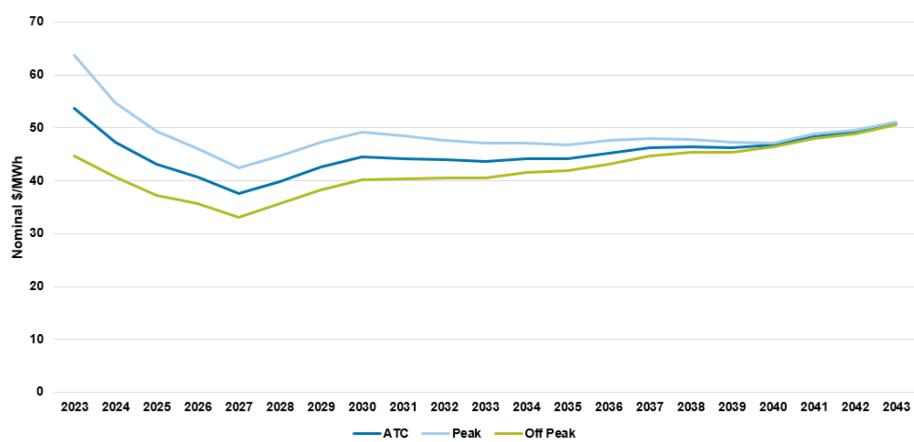
Exhibit 16 Annual Around the Clock MISO Zone 5 Electricity Price ($nom/MWh)



Power prices (nominal$) range from an upper boundary of $70/MWh in the BaseHighHigh case to the lower one represented by prices around mid-$30s/MWh in the BaseLowLow case.

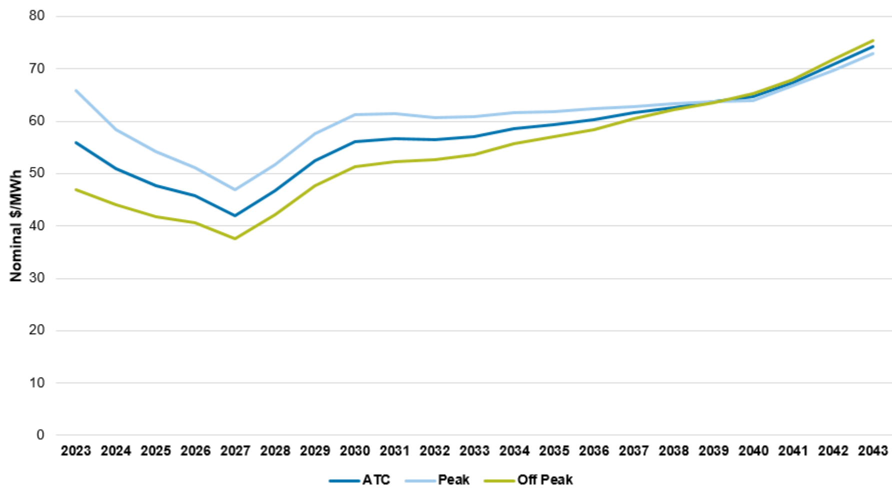
- The cases also experience a peak/off-peak price convergence, as illustrated in Exhibit 17, which shows the MISO Z5 price outlook for the BaseBaseBase case. With high levels of renewables and storage added to the system, the prices in the BaseBaseBase case completely converge by 2040.

Exhibit 17 Base Base Base Zone 5 Energy Prices ($/MWh)



- For the BaseHighHigh case depicted in Exhibit 18, the off-peak is higher than the peak price in the late 2030s. With higher NG price and CO2 price, hours where fossil resources are marginal begin to have greater impacts on pricing – especially in the off-peak hours where no solar is available. This phenomenon is already taking place in places like California, where the region has experienced a significant entry of solar and storage resources lately.

Exhibit 18 Base High High MISO Zone 5 Energy Prices ($/MWh)



- On the load varying cases (HBB and LBB), prices have not diverged from the BaseBaseBase case significantly. In general, lower load depresses prices while higher load enables greater prices spikes, assuming everything else remains constant. However, once the system rebalances with enough supply and the marginal resources remain similar, the impact on prices becomes more subtle over time.

As briefly described above, on- and off-peak prices converge over time. In other words, on peak prices generally remain flat-to-declining over time, while the off-peak prices increase at a much faster rate. Exhibit 19, Exhibit 20 and Exhibit 21 below provide additional details around how the energy prices, system demand and generation evolve over time. In summary, the following factors contribute to the pricing convergence indicated above:

- On the supply side, renewable generation and storage penetration increase over time. The increase in output by these resources, decrease system net loads[4] across all seasons, with the spring and fall seasons experiencing the largest decline. In terms of generation, on average the output from these resources is the highest during the traditional peak periods, e.g. 8 am to 5 pm, although output from wind and storage still increase considerably during the rest hours.
- On the demand side, the system net load generally declines due to the increase of renewable generation. Net load flattens and on average – over time - exhibits lower demand requirements during daytime across all seasons. Particularly during spring, the system net demand is projected to drop significantly. Also, with lower net system demand during these periods, the system can rely on more efficient units and hence realize lower system LMPs.
- The combination of increasing zero- or low-operating-cost supply and declining net system requirements over time during the day places significant downward pressure on prices, leading to flat to declining on-peak LMPs in CRA's projection.
- During off-peak periods, system net loads decline over time, but coupled with aggressive fossil fuel retirements, system LMPs continue to be set by more

[4] Net load is defined as gross load net of renewables and storage output

expensive resources in the system. With increasing natural gas and CO2 prices, LMPs during the off-peak period increase at a faster rate over time.

Exhibit 19 Average Hourly Price by Season in 2030 and 2040

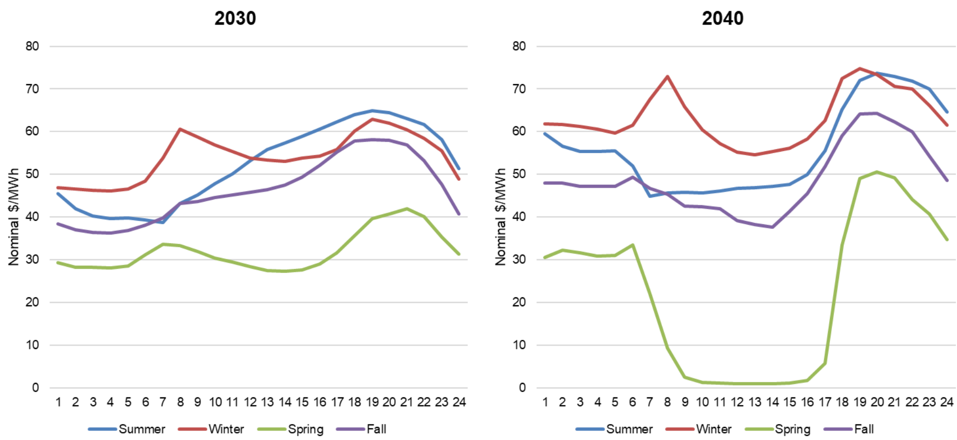
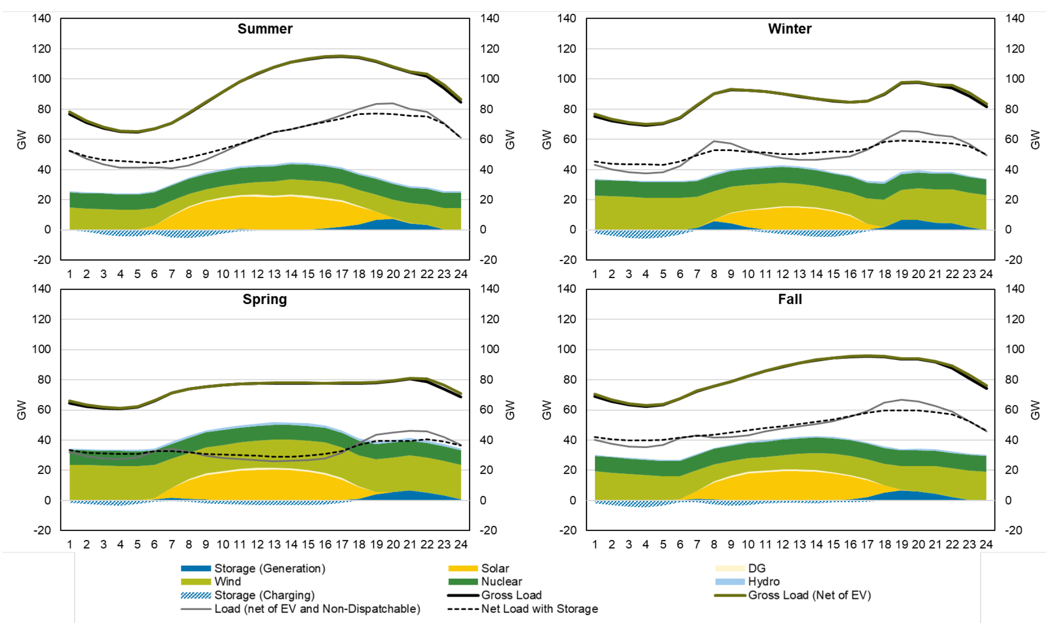
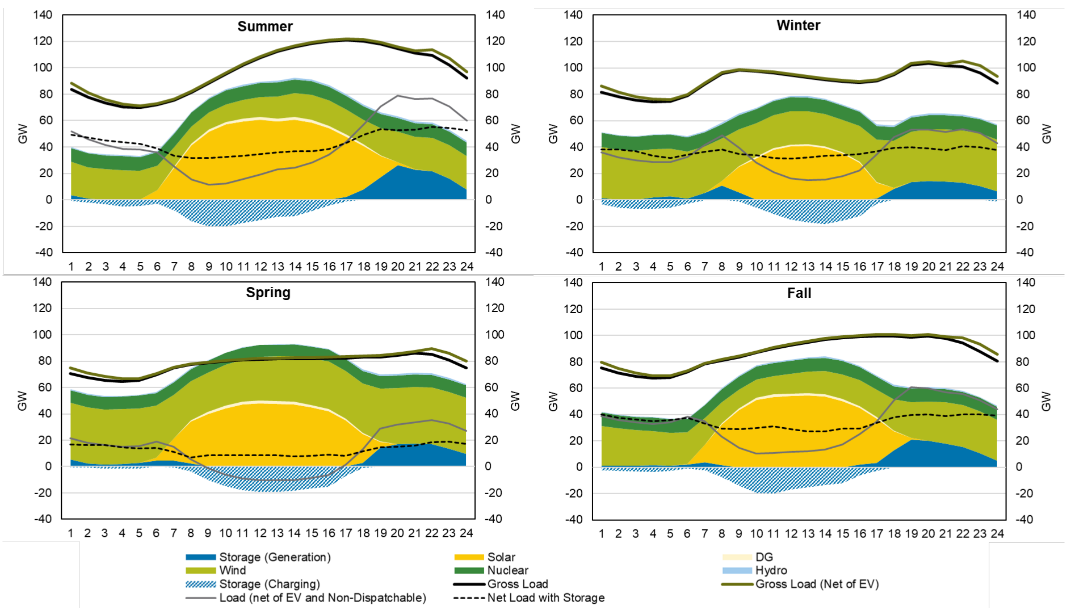


Exhibit 20:2030 Average Hourly Load and Generation Profiles[5]



[5] Net Load with Storage = Gross Load (Net of EV) – Solar – Wind – Nuclear – Hydro – Storage

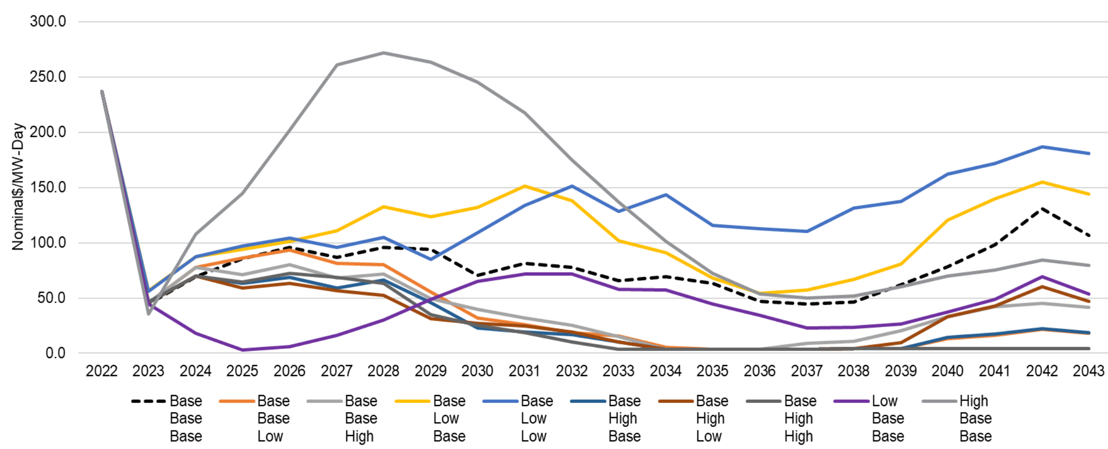
Exhibit 21: 2040 Average Hourly Load and Generation Profiles



3.5. MISO Capacity Market Price Results

In addition to the energy market, MISO also operates a capacity market that procures capacity on a seasonal basis. The capacity market is based on an administratively set demand requirement and supply offers from market participants that are willing to sell capacity. The exhibit below depicts CRA's MISO's capacity market projections for nine modeled cases. Note that the cases are described by how the three different variables are modified. For example, BaseBaseBase signifies a case that incorporates Base Load, Base Gas and Base Carbon price projections.

Exhibit 22 MISO North Seasonal Capacity Price Outlook - Annual Average in Nominal $/MW-Day



For the BaseBaseBase (BBB) case, following the recent price spike in the 2022-23 auction, CRA expects tight supply market conditions over the next couple years with the market

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reacting to the higher prices by delaying retirements, imports might recover, and PRM reduces to 7.4%. In the near-term, new entry remains limited and continued fossil retirements are planned. Into the late 2020s and early 2030s, IRA-related new entry and replacement capacity continue to expand and CRA expects capacity prices to trend down. Over the long term, prices remain in the $60-100/MW-day range, reflecting an average balance necessary to maintain existing resources and procure new resources.

Winter prices are on par with fall for the most part over the near-term, even though prices in the winter do not clear at CONE. In the 2020-21 and 2021-22 winter assessment reports published by MISO, winter reserve margins were projected to stay in the 40% range a year or two prior to 2022. However, there is likely a case for higher-than-normal outages going forward especially given the winter storms that happened in 2021 and 2022.

- BBL, similar to above, is projected to remain high over the near term, where continued fossil retirements drive system tightness. Over time, due to a lack of carbon pressure, capacity requirements from high carbon emitting resources are relatively relieved. Prices trend to a lower level, as aging facilities are timely replaced by new intermittent resources.
- The near-term prices in the BBH scenario are expected to remain elevated following the recent price spike and the ongoing planned retirements. The high CO2 prices provide enough incentive for new renewables and storage capacity to enter the market and to fully displace existing units. The price downward from the current high through mid-2030s until the eventual fossil retirements require more capacity. However, on average the price level is not significant compared to today's level.
- In the BLB case, the combination of low NG and base carbon pressure results in early coal retirements. Moderate energy prices in this case do not provide enough economic benefits for renewables replacements. As a result, capacity prices in this case remain elevated throughout the forecast period.
- The BLL case is similar to the BLB case because low natural gas prices continue to pressure existing coal facilities towards early retirement. Throughout the forecast period, lower renewables entry compared to the BBB case and generally more stringent environmental regulations create unfavorable conditions for new gas entry. Under this environment, the combination of accelerated coal retirements, higher capacity requirements, and lower renewables entry contribute to persistently high capacity prices with new gas entry gradually replacing part of the fossil fleet.
- BHB, BHL, and BHH cases are projected to have similar capacity requirements, as strong energy market performance provides adequate pricing signals to aggressively replace existing fossil fuel capacity with new entry resources – especially new renewables and storage - timely and efficiently.
- Across all scenarios, BBB's capacity prices are in the middle, whereas BBL and BBH are on the lower end due to stronger prospects for new builds. BLB and BLL are on the higher end because of deteriorating coal resource economics, accelerated retirements, and overall weaker prospects for new replacements.

In addition to the main nine cases, CRA also performed two additional sensitivities that evaluate the high and low load forecast projections. The LowBaseBase (LBB) case evaluates the impacts of lower load forecast compared to the Base case, while the HighBaseBase (HBB) case evaluates the impacts of higher load than the Base.

- Compared to the BBB Case, the LBB case capacity prices are lower, primarily driven by flat-to-declining peak load over time. The lower load not only makes the emissions

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goal more achievable, but also leads to less pressure in terms of having to meet additional peak requirements with resources that have lower peak values.

- In contrast with the LBB case, the prices in the HBB are higher than the BBB. With winter peak load growing by 3 GW per year over the next 20 years, significant risks center around the winter season. While capacity prices likely remain high over the near term, winter remains the period at risk throughout the study period.

4. MISO Ancillary Services Analysis

MISO has operated an Ancillary Services (AS) Market for regulation and contingency Reserves since 2009. Currently, MISO procures ancillary services in the Day Ahead and Real Time markets, which are simultaneously co-optimized with its energy market. MISO's contingency reserve consists of two separate products for Spinning Reserves and Supplemental (Non-spinning) Reserves.

Spinning Reserves can be provided by either generation resources or demand-side resources and must be synchronized to the grid and able to dispatch energy within ten minutes of receiving an instruction to do so. There is a fixed requirement of around 1000 MW for Spinning Reserves. Supplemental Reserves are also provided by qualified generation and demand side resources, but these resources do not need to be synchronized to the grid but must be able to start up and adjust output within ten minutes of receiving a dispatch signal from the MISO. There is a fixed requirement of around 1000 MW for Supplemental Reserves. [6]

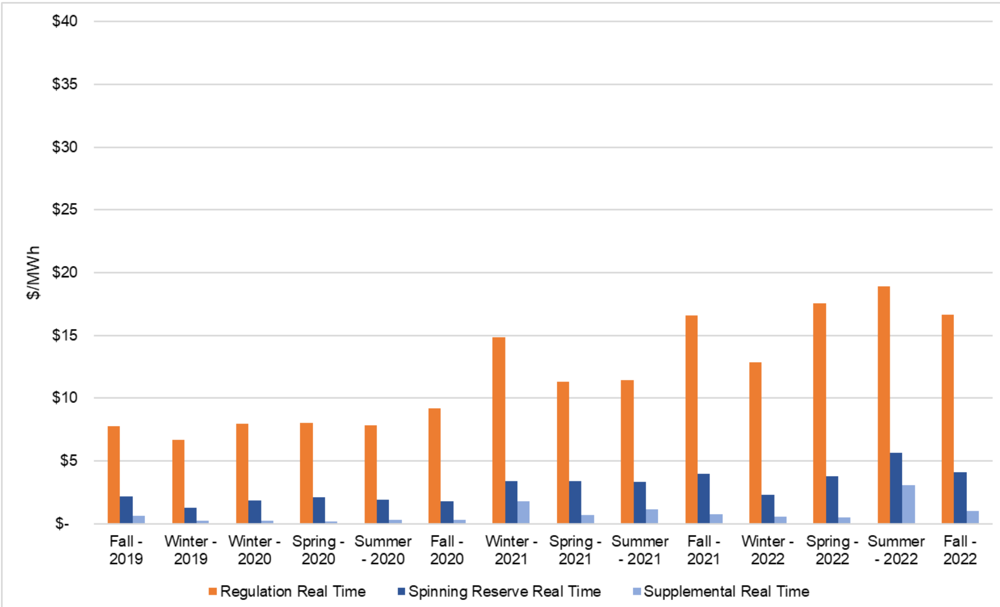
Regulation reserves generation-based resources and stored energy resources. These resources must be able to adjust their output in response to automatic signals within five minutes of receiving a signal to do so. MISO has only a single product for Regulation Reserves applied across all zones with a requirement that varies between 300 MW and 500 MW, depending on system conditions. This requirement is not based explicitly on NERC standards, but rather on operational experience.

Lastly, MISO has recently implemented a 30 min short term reserve product that seeks to procure online or offline resources that can provide incremental energy within 30 minutes. The product separately addresses market-wide, sub-regional and local short-term needs. The market wide short term 30-minute requirement is set at 1.5 times the largest generator contingency.

Price for ancillary services have remained between $7-20/MWh on average for regulation and $1-8/MWh on average of the operating reserves.

6 https://www.ercot.com/files/docs/2019/09/18/4._MISO_Energy_and_Ancillary_Service_Co-optimization_091819.pdf

Exhibit 23 Average Regulation, Spinning and Supplemental Reserve Prices($nom/MWh) (2019-22)



Notably, due to the nature of these markets, hourly prices can reflect short but very lucrative in value time periods, when the system is under duress. As depicted in the table below, summer and winter seasons tend to experience higher maximum prices than fall and spring, when historically the system has experienced less periods of reserve shortages.

Exhibit 24 Ancillary Prices Historical Descriptive Analytics

Regulation Prices				
	Average Price $/MWh	Max Price $/MWh	Min Price $/MWh	StdDev of Price $/MWh
Fall	$12.40	$373.17	$1.62	$10.09
Spring	$12.39	$214.64	$1.39	$5.97
Summer	$12.76	$941.76	$1.63	$7.35
Winter	$11.23	$492.09	$1.32	$5.99

Spinning Prices				
	Average Price $/MWh	Max Price $/MWh	Min Price $/MWh	StdDev of Price $/MWh
Fall	$2.96	$324.22	$0.00	$7.71
Spring	$3.25	$205.85	$0.04	$4.73
Summer	$3.75	$851.51	$0.00	$6.40
Winter	$2.46	$434.63	$0.00	$4.71

Supplemental Prices				
	Average Price $/MWh	Max Price $/MWh	Min Price $/MWh	StdDev of Price $/MWh
Fall	$0.50	$275.15	$0.00	$5.70
Spring	$0.37	$188.47	$0.03	$3.18
Summer	$1.20	$801.29	$0.00	$4.99
Winter	$0.79	$434.63	$0.00	$3.48

4.1. Ancillary Services Market Value Estimate

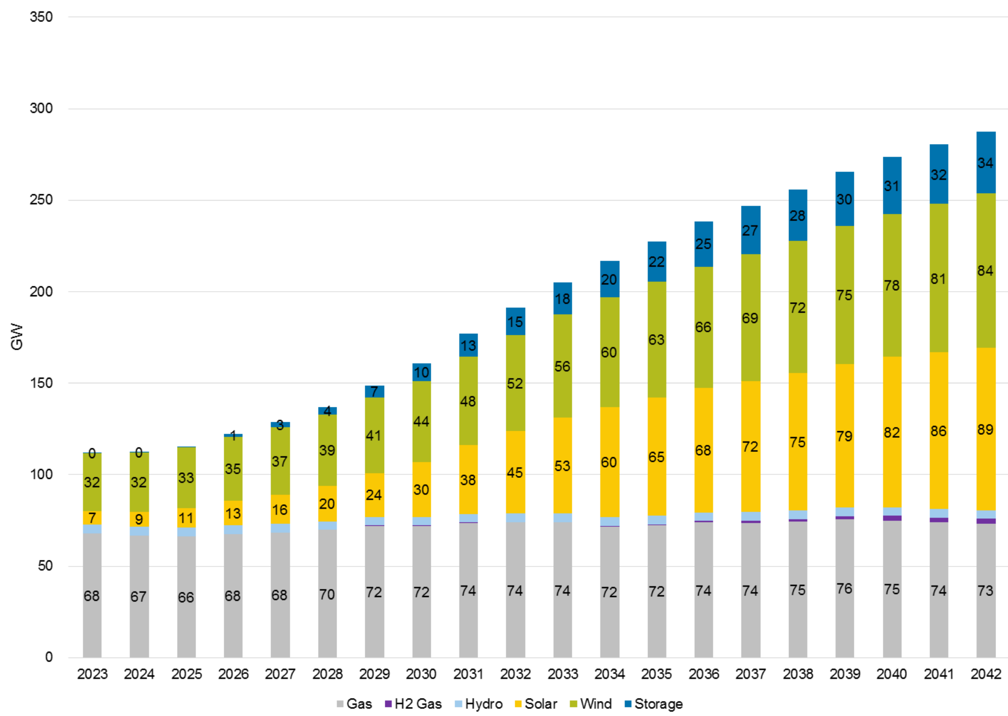
As mentioned above, the AS markets are quite shallow (roughly 300-500 MW for regulation and around 2 GW for combined operating reserves) at consistent historical levels for prices and total revenues. Although the requirements for such services have remained static in the past, the expected changes in MISO's resource mix with the significant influx of intermittent resources and energy storage and the eventual exit of traditional dispatchable resources will likely affect the structure of the ancillary services market and as a result its pricing and potential value. In addition, expected changes on the demand side – enhancements on load dispatchability – combined with more frequent occurrences of high impactful stressed system events will also have an impact on the need for ancillary services in the future.

Various studies[7] have examined how the wholesale energy and ancillary services markets will be affected by the influx of energy storage and renewable generation together with more frequent system stressed conditions. The studies identified the need for ISOs and market participants to think about the changing system in a holistic manner (energy, capacity and ancillary services). For example, one of the findings was an interesting interaction between the ancillary and energy markets. Baseload resources (including coal and natural gas combined cycle) that participate in both the energy and reserve markets shift capacity towards generating, when the renewable production does not match the expected output thereby reducing their reserves. Because these plants are cheaper to operate than peaking capacity, this behavior reduces the market price below peaking resource marginal costs, thereby requiring more uplift which is inefficient for the market. Various ISOs have tried to mitigate this inefficiency by establishing ramping products that compensate resources on a competitive basis for such instances. Although early, similar market reforms will be more common in the future.

Since the effect on the Ancillary Services requirements from the system and market participation changes is difficult to estimate without a more detailed study, CRA focused on the ancillary services supply over time to determine how the AS market may behave. The expected build of the BaseBaseBase case provides a reasonable outlook on the amount of the resources that mostly affect the ancillary services construct – both on the demand and supply side.

[7] Penn State Study

Exhibit 25 BaseBaseBase Capacity Mix over the study period (GW)



As depicted in the graph, more than 30 GW of new storage is expected to enter the market over the study period. Although AS markets currently provide a premium to wholesale energy markets in many hours, as more storage is brought into the region, which is very effective at providing these services, it is expected that the A/S market value will be negatively affected. However, as mentioned above, the demand for A/S is expected to increase due to the proliferation of renewables and more frequent system disturbances. MISO and CAISO have established ramping products with the expectation that the demand for these services will increase over time.

Therefore, for this analysis, it is reasonable to assume that total margin compensation of flexible, dispatchable resources, whether that be from sales of energy or sales of ancillary services, is expected to be similar to total margin compensation total margin compensation were these resources to dispatch only for energy.

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