MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

- DECEMBER 2020 -

Living Document

MISO is releasing this report as a "living" document which will be updated over time as conditions evolve and as MISO, stakeholders, and states continue to learn about the Reliability Imperative

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A Message from John Bear, CEO

The electric industry is changing in profound ways.

The industry's longtime reliance on conventional baseload power plants is declining sharply, driven by economic factors and consumer preferences for clean energy, among other things.

Meanwhile, the grid is becoming increasingly reliant on wind and solar resources that are available only when the wind is blowing, or the sun is shining.

To be sure, there are upsides and opportunities associated with these trends. But the changes we are seeing also pose a host of complex and urgent challenges to electric system reliability in the MISO region.

Utilities, states, and MISO all have roles to play to address these challenges. MISO calls this shared responsibility the **Reliability Imperative.** We think the word "imperative" is appropriate for several reasons. First, the work we are doing is not optional—to maintain system reliability, we must respond to the unprecedented change we and our members face. Second, this work cannot be put off for months or years—much of it has long lead times, so we need to act now. And third, our stakeholders are counting on us—regulatory agencies, utilities and other entities are looking to MISO to identify problems and find solutions.

This report describes the many interconnected efforts that MISO is pursuing in the realms of markets, operations, and planning to meet that charge. The report is also designed to be "living" so it will be regularly updated and expanded as we learn more and our path forward becomes clearer.

The energy industry and our region are changing in big ways, and MISO is planning for what lies ahead. We hope you will find this report to be engaging and useful as we confront these new challenges and opportunities together.

Thank you,

Executive Summary

THE REGION IS CHANGING IN BIG WAYS

The electric system is increasingly fueled by wind and solar, driven by favorable economics for energy production, technological advances, state policies, and consumer preferences for carbon-free energy, among other things.

Looking at the marginal cost of energy produced, wind and solar are lower cost than coal, nuclear, or natural gas generation. As a result, the growth of these renewable resources continues to replace the region's conventional baseload resources that constituted the backbone of the region's electric system for decades.

There are many system and societal benefits of these changes. Innovative generation and grid technologies have the potential to reduce customer rates and bring efficiencies to the system. The shift to cleaner fuels will benefit the health of our communities and is key to addressing the risks of a changing climate. With a diverse regional footprint and managing all of the connections with our seams neighbors, MISO is well-positioned to support our members as they transition their fleets.

THESE CHANGES WILL CHALLENGE SYSTEM RELIABILITY

While MISO is policy-neutral on these and other trends, MISO has observed they pose a number of significant challenges for the region's electric system and we must adapt to maintain required and expected levels of reliability. As the independent system operator, MISO has responsibility to maintain electric reliability, which it does by addressing the holistic needs of the system – for example for energy, capacity, resource adequacy, and flexibility.

Each resource type provides a different mix of these capabilities. As the region's resource mix changes, we must understand what capabilities are needed to maintain reliability and ensure that sufficient amounts of those resource capabilities are available when needed.

- Wind and solar resources are not always available to provide energy during times of need.
- Conventional baseload resources that remain in service can be more prone to outages given their changed usage patterns and maintenance cycles, rendering them potentially unavailable when they are needed most.

As the system relies more on renewables, the region is also becoming more dependent on resources connected to local distribution systems or located behind customer meters, as well as on demand-side resources that currently are only used in emergencies. Generation fleet change and extreme weather are increasing risk across the entire year (not just in the summer). MISO's Renewable Integration Impact Assessment concludes that the complexity of planning and operating the grid increases exponentially beyond 30% of the load being served by wind and solar, requiring more coordination and advanced action to maintain grid stability at higher renewable penetration levels. Already there are areas within the MISO system where local renewable penetration is above 30%.

WE HAVE A RELIABILITY IMPERATIVE TO ADDRESS THESE CHALLENGES

MISO, members, state regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges. MISO calls this shared responsibility the MISO Region Reliability Imperative because the reliability-enhancing work it requires cannot be delayed. This work will also enable utilities and states in the MISO region to invest in the type of infrastructure that is needed to meet energy needs and policy objectives going forward.

This report lays out MISO's response to the Reliability Imperative. MISO's response is holistic in approach, consisting of numerous efforts and initiatives that are designed to work in concert with each other to mitigate the challenges facing the region. MISO organizes this work into four main categories: (1) Market Redefinition, (2) Long Range Transmission Planning, (3) Operations of the Future, and (4) Market System Enhancements. Below is a brief look at each.

1. **Market Redefinition:** The initiatives in this category aim to ensure that resources with the types of capabilities and attributes the system needs will be available in all 8,760 hours of the year. This is important because as noted above, the region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges. Specific efforts in this area include providing a longer-term and deeper assessment of system needs across all hours of the year, including required capabilities such as flexibility; shifting to verifying sufficient generation adequacy across all hours of the year; improving how resources are accredited; ensuring that prices accurately reflect market conditions, especially during emergencies; and development of market products that provide the right incentives for resources to maintain system reliability.

2. **Long Range Transmission Planning:** This effort is designed to identify what transmission the region will need going forward as the electric industry continues to evolve. For example, building additional transmission is especially crucial to support the continued growth of large-scale wind and solar, since those resources are often located far from load centers. A robust transmission plan can also reduce the cost of electricity for consumers by signaling better locations for resource siting that deliver fuel cost savings, decarbonization, and flexibility.

3. **Operations of the Future:** This effort is designed to ensure that MISO will have the kinds of skills, processes, and technologies it will need to effectively manage both wholesale and retail connected resources. For example, this initiative will leverage artificial intelligence, machine learning and advanced analytics among other tools to help future MISO control-room operators effectively forecast, visualize, and manage grid uncertainty. It will also help MISO to better manage maintenance and "pre-position" the grid ahead of system changes such as weather.

4. **Market System Enhancements:** This category of work is designed to transform MISO's historical system—which was built in the early 2000's—into a more flexible and secure system that will meet the needs for years to come. Current systems and technology are not capable of accommodating the increasing demands for new, reliability-driven market enhancements and fully leveraging the opportunities of new resource types such as storage and residential generation options (like rooftop solar) to meet future challenges. This initiative will employ flexible architecture and analysis to support the evolving resource mix and future-state processes for operating MISO markets.

PURPOSE OF THIS REPORT

The purpose of this report is to provide MISO stakeholders with an organization-wide view of MISO's plan to address the Reliability Imperative amidst a rapidly changing energy landscape. The goal of this "living" report is to lay out the context for critical Reliability Imperative initiatives, how they fit together, feedback plans and project timing. This "living" report will be updated with accompanying materials as specific plans mature and additional information is gathered.

While grid operators have managed uncertainty for decades, and MISO has continuously pushed to improve and evolve since day one, we are preparing for an unprecedented pace of change. By actively pursuing this strategic collection of coordinated initiatives, MISO will ensure ongoing system reliability while enabling members' future plans. There is a huge amount of work to do and we will only succeed if we move forward transparently, collaboratively and swiftly.

STAKEHOLDER INPUT IS CRUCIAL

Much of the work cited in this report is already underway. Many of the ideas and proposals in this report reflect a great deal of technical input from stakeholders. For example:

- MISO proposals to assess resource adequacy more than once a year and to improve how resources are accounted for are discussed at the MISO Resource Adequacy Subcommittee.
- Similarly, MISO initiatives for emergency pricing and the Market System Enhancement effort reflect input at the MISO Market Subcommittee.
- Member plans and stakeholder input shaped the MISO Futures planning scenarios over multiple workshops.

Other proposals in this report are not in the stakeholder process because they are in development and not yet ready to be discussed with stakeholders or they are focused on internal MISO processes.

THE RELIABILITY IMPERATIVE DOES NOT REPLACE EXISTING INITIATIVES OR PROGRAMS

This report, and the initiatives it describes, should not be viewed as a brand-new effort by MISO. The Reliability Imperative is not intended to replace existing initiatives that stakeholders are already familiar with. Instead, this report brings together a number of strategic initiatives with the purpose of ensuring more alignment and highlighting the connections.

That said, this report is written from MISO's perspective. Not every proposal and initiative in this report will be supported by every one of MISO's stakeholders, given the range of policy goals, business models, and other interests. MISO welcomes feedback on this report but MISO also recognizes that the Reliability Imperative warrants an immediate response. The time to act is now.

Informing MISO's Response to the Reliability Imperative

MISO's response to the Reliability Imperative has been informed by years of conversations with our stakeholders. Additionally, MISO has performed extensive modeling of the changing risk profile. To review:

MISO Forward 2019: The first of the Forward series described the implications of a changing resource mix, including how the '3Ds' – de-marginalization, decentralization, and digitalization – led to MISO's focus on enhancing Availability, Flexibility and Visibility ("AFV"). You will find these themes in the Reliability Imperative initiatives. These AFV themes have informed much of the following MISO work.

MISO Forward 2020: The MISO Forward 2020 report shows that changes will not be the same across all members, as different states and utilities adopt a range of business models and generation, all of which MISO will support through the Reliability Imperative work.

Renewable Integration Impact Assessment (RIIA): MISO's 4-year initiative to understand the impacts of increasing renewables on the MISO system. The key conclusion is that planning and operating the grid becomes more difficult beyond 30% of the footprint-wide load being served by wind and solar, and that with coordination and advanced action the MISO region could achieve 50% or higher. The workshop materials are available now, and a report will be published in early 2021.

Resource Availability and Need (RAN) Initiative: Ongoing analysis of MISO's changing risk profile and evolving system needs as outlined in five whitepapers. The analysis has informed changes to the value of wholesale load that can respond to the market and plant outage coordination, and development of resource adequacy changes. Because Resource Adequacy must compliment market design and real-time tools/process, the work is central to the Reliability Imperative effort.

MISO Futures: A product of continued collaboration between MISO and its stakeholders, the three MISO Futures provide a set of bookends to explore a wide range of future outlooks. Updated this year with the annual transmission planning cycle, these forward-looking planning scenarios are being used throughout the organization to prioritize and pace the Reliability Imperative work.

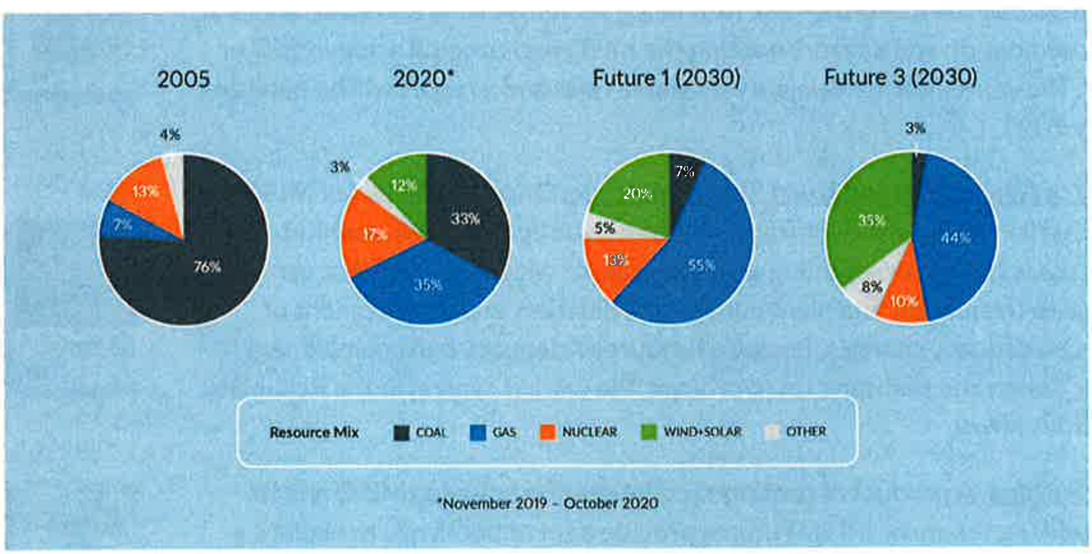
MISO Forward 2021: To be published early 2021, the next report in the Forward series will focus on what changes are needed from MISO as adjacent industries, such as buildings and transportation, evolve how they interact with the electric ecosystem. The Reliability Imperative will remain closely in step with these expectations.

From this groundwork, we know that there are challenges ahead. But we can also see that there is opportunity for the large, interconnected footprint that MISO provides. We are determined to do the hard work required to ensure all of our members and their end consumers benefit from MISO membership.

The timing of much of the Reliability Imperative work will be impacted by the pace of new generation coming on the system. MISO has multiple views on the future generation fleet and, importantly, the speed of change being set by our members. MISO is currently operating a 25,000 MW wind fleet which, in MISO's most recent 12-month history generated 12% of the electricity mix (solar less than 1%). MISO is preparing for an additional 15,000 MW of renewables (10,000 MW of solar and 5,000 MW of wind) on the system in the next few years.

Beyond that, MISO looks to the MISO Futures modeling to capture the bookends of resource mix possibilities. The figure below shows 2030 planning scenarios for the conservative pace of change (Future 1) and the more aggressive pace (Future 3):

MISO Generation Mix (% of MWh)

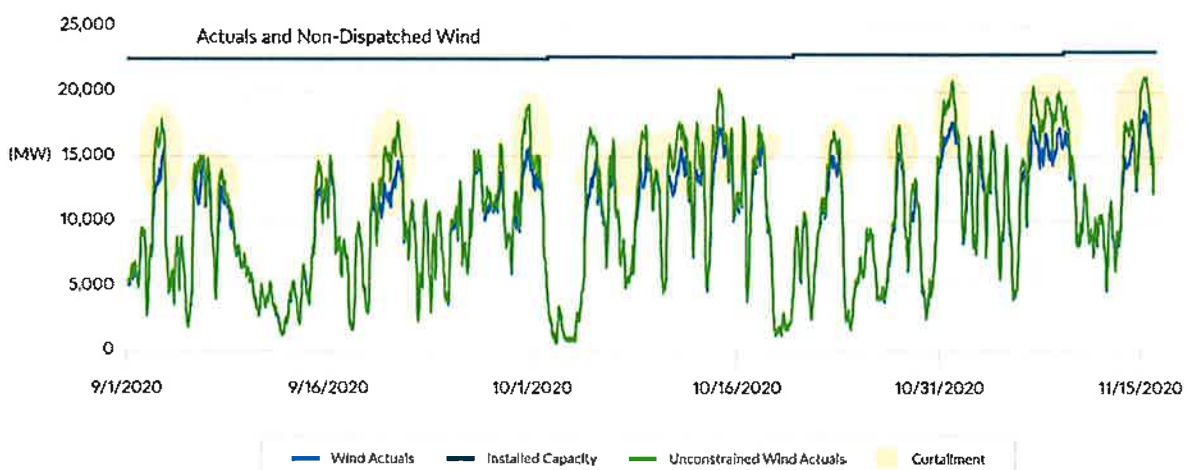


Current Reliability Challenges Will Become More Significant

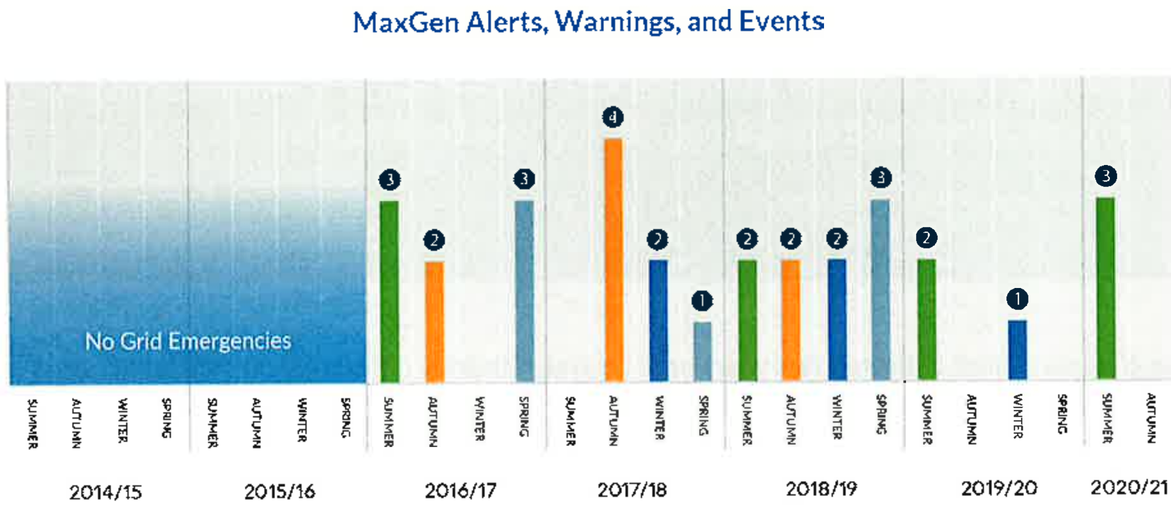
> "We see very little risk of over-building the transmission system; the real risk is in a scenario where we have underbuilt the system. Similarly, across markets and operations, our job is to be prepared."
>
> Clair Moeller, MISO President

Real-time conditions in the last few years have been significantly different than the first 10 years of MISO operations. Power plant retirements, lower overall reserve margins, and increasing outage levels of conventional generation have required MISO to operate with less available capacity than in the past. A growing fleet of renewables that operate differently and, as the graphic below illustrates, can fluctuate on a day-to-day and even an hour-by-hour basis. At times of high wind output, transmission congestion is leading to increased levels of curtailment (highlighted by the orange circles in the chart below). Additionally, non-traditional resources such as load that can respond to system needs and energy efficiency are increasingly being used. And as the climate changes, history becomes a less reliable predictor of future conditions.

Recent Examples of MISO wind generation variability and curtailment



MISO has declared an increasing number of emergencies since the summer of 2016. While the emergency protocols are a legitimate way for MISO to access additional resources and not a direct indicator of a reliability issue, calling on them more and in non-traditional times are evidence of MISO's changing risk profile.



Most events are the result of multiple factors happening at the same time. Factors include more planned and/or unplanned generation and transmission outages, high demand conditions, and more extreme temperatures and storms.

Market Redefinition

Generation mix evolution increases the focus on having enough energy for every hour of the year. MISO is addressing this changing risk profile across markets, planning, and future-looking studies. As the generation mix changes, it is important for MISO to provide signals about what will be needed to ensure reliability, and to give the right price incentives when the system is in need. Markets can provide useful signals across multiple time frames.

Resource Assessments: In the investment and planning timeframe, MISO should provide information to all members about the impact of their plans in aggregate. Today, planning is focused on the summer peak hour for the coming year or two. The voluntary Organization of MISO States (OMS) survey looks at several years ahead, but confidence is lower in the later years. Additionally, the OMS survey only focuses on capacity, but increasingly the system will need a forecast of flexibility and other attributesGoing forward, MISO is developing the ability to provide forward resource assessments and long-term resource adequacy reports to better inform future investment and retirement decisions.

Meeting Forecasted Needs: Currently, MISO utilizes both planning requirements and energy market price signals to inform investment decisions and pay resources for providing energy when most needed. Since 2017, the Resource Availability and Need (RAN) initiative has focused on near-term improvements in both planning requirements and energy markets. MISO, and the electric industry in general, are also considering the right balance between planning requirements and energy markets in ensuring energy is available in every hour of the year; for now MISO is focused on 'no regrets' modifications for both planning and markets. One important group of changes looks at updating how resources are accredited – including conventional, intermittent, and emergency-only resources.

Resource Adequacy Construct: In the planning horizon, MISO is looking to better reflect the changing risk profile. MISO's construct was designed around a conventional fleet of resources. In this system, outage risk was concentrated during the summer. Since the early 2000s, the fleet has moved to more renewable resources that are variable and outage risk has expanded beyond the summer months. MISO's mechanisms must be updated to reflect the changing risk. In the near term, MISO plans to make the Planning Resource Auction a "sub-annual" construct to reflect the changing risks. Importantly, the future Resource Adequacy construct will also need to be adaptable as the portfolio and risk profiles continue to evolve.

Increased Reliance on Energy Market Pricing: MISO is working to update prices to more accurately reflect the value of additional energy during times of system constraints. MISO is in the process of improving emergency and scarcity prices to more accurately convey system conditions and help incent and ensure reliability in tight grid conditions. MISO will continue to evaluate the changing risk profile to assess the effectiveness of energy market products and pricing and will explore potential new products and approaches.

"Market Redefinition means we need to consider the broad and transformative implications of the rapidly changing risk profile in MISO. This is driving our agenda to re-think the methods by which we assess reliability risk in the planning and operating horizons and the ways in which our markets incent and ensure availability and flexibility."

Richard Doying, MISO EVP Market & Grid Strategy

MARKET REDEFINITION ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Resource Adequacy Construct	• Regional resource assessments of changing reliability risk profile	• Reliability requirements & metrics • Sub-annual construct • Accreditation enhancements		• Enhanced deliverability for conventional and intermittent capacity resources (Installed Capacity filings) • Load Modifying Resources Accreditation
Energy Market Signals	• Uncertainty and variability management • Emerging technology participation (e.g. hybrid and Distributed Energy Resources) • Optimize transactions at the seams (transmission & distribution interface, and bulk electric system)	• Improve scarcity pricing and price formation • Enhancements for long-lead units and self-commitments • Multiple Configuration Resources • FERC Order 2222 (Distributed Energy Resource) compliance plan • Enhance market-to-market coordination process	• Enhance emergency pricing • Build Short-Term Reserves product • FERC Order 841 (storage participation) product	• Multi-day Operating Margin forecast • Distributed Energy Resource Visibility and Communication whitepaper • Improvements to MISO-SPP & MISO-PJM market-to-market process

Long Range Transmission Planning

Renewables such as wind and solar work with the transmission system very differently than conventional power plants. For this reason, the ongoing trend of conventional resources retiring from service as intermittent renewables continue to grow poses significant challenges to the reliability of the transmission system in the MISO region. These challenges are framed up in MISO's Renewable Integration Impact Assessment work.

Fortunately, MISO can leverage its large footprint and resources to ease some of the challenges. One of the keys will be transmission projects that support these new resources in the region.

MISO is doing this through a Reliability Imperative initiative called Long Range Transmission Planning, or LRTP. LRTP is designed to assess the region's future transmission needs, starting from a base of the utility and state plans on where to site and build new resources.

It is important to keep in mind that LRTP does not replace other transmission-planning efforts that have long existed at MISO, such as the annual studies contained in the MISO Transmission Expansion Plan, or MTEP. LRTP will coordinate closely with those efforts, and it will also be a transparent and cooperative part of the MISO stakeholder process.

Futures / Policy Consensus: The LRTP work is grounded in the three robust future scenarios developed over the past year. MISO will prioritize meeting the reliability challenges embedded in Future 1, while ensuring that outcomes do not foreclose Futures 2 and 3. Future 1 tries to reflect current MISO member plans across the footprint and various policy objectives of the states. Futures 2 and 3 reflect increasing levels of electrification (e.g., more electric vehicles) and renewables.

Business Case Development: MISO will help stakeholders assess the business case for LRTP projects by analyzing multiple benefits relative to the costs. The business case should reflect the need for transmission to ensure reliability of the system, in addition to any economic benefits, given the policy and fleet transition objectives of stakeholders. This includes helping stakeholders consider both generation and transmission costs and benefits on a holistic basis, including the value of flexibility that transmission provides. For example, we will need to assess: (1) congestion points that limit energy imports into certain zones; (2) constraints between the MISO South subregion and the North/Central subregions; and (3) energy transfers between MISO and neighboring systems, such as Southwest Power Pool and PJM.

Cost Allocation: A key aspect of LRTP will be to ensure that the costs of new transmission projects are allocated fairly. This means MISO and stakeholders will work together to adjust existing or develop new cost-allocation methods. The Organization of MISO States (OMS), which represents our state regulatory agencies, has established a working group to focus specifically on transmission cost allocation issues. MISO is committed to working with that OMS group and other stakeholders on this important topic.

LRTP is a comprehensive "transmission roadmap" that will identify and drive investments in transmission projects addressing all needs of the region as the resource fleet continues to evolve. The roadmap will be updated as needed to align with evolving resource fleets and business plans, state energy/environmental policies, and other dynamic factors that affect the region's transmission needs. As solutions are identified through LRTP, they will be moved into the ongoing MTEP process for final approval by MISO management and Board of Directors. MISO anticipates delivering the first round of suggested LRTP solutions to the Board of Directors in December 2021. Specific projects in the Explore, Decide, Do table will inform recommendations.

> "If you love renewables you'd better love transmission."
>
> John Bear, MISO Chief Executive Officer

LONG RANGE TRANSMISSION PLANNING ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Futures / Policy Consensus			• Continue to understand member plans, Integrated Resource Plan trends, state policy objectives	• Update MISO Futures
Business Case Development	• Study non-transmission alternative solutions • Determine increased potential for High Voltage Direct Current (HVDC) lines	• Conduct special zonal studies • Deliver first round of suggested Long Range Transmission Plan solutions to MISO's Board	• Increase MISO North/South transfer capabilities • Enhance renewables integration in the upper Midwest (MWEX-area) • Address import / export limitations in Michigan • Improve seams via Joint Study with SPP	• Multi-Value transmission projects • Ongoing improvements to the generation interconnection process
Cost Allocation	• Benefits/Cost allocation for identified Long Range Transmission Plan projects			

Operations of the Future

MISO Operations will also be challenged by the different types of resources connecting to the grid including at the residential level. Work is underway to ensure that the people, processes, and technology allow MISO to respond. This work, termed Operations of the Future, is initially focused in the near-term on two large buckets of work – operational planning and situational awareness.

Operations planning improvements can help manage supply and demand variability in every hour. The shift to more weather-dependent, intermittent renewables and distributed resources mean that system peaks and operating risks are becoming less obvious and more difficult to manage in day to day operations. The planning assumption that most days follow predictable load profiles is also being challenged given the rise of demand responding to market prices. With the changes in the system, better forecasting will capture more unknows into operations and market decisions. Outage coordination will also be enhanced to determine and approve planned maintenance outages, thus providing more windows of opportunity. MISO is further investigating enhanced 'look-ahead' commitment of both generation and demand to capitalize on the flexibility of the grid to meet various system conditions. Finally, MISO is seeking improved methods to position the grid ahead of system challenges such as volatile weather patterns and improve our preparation and management of grid events.

> "In the past, most days were the same. In the future, most days will be different and we need the people, process and technology to deal with that variability.
>
> Jennifer Curran, MISO VP System Planning and Chief Compliance Officer

Situational awareness can be improved to turn data into actions. Today, MISO Operations relies heavily on the expertise of its operators. While operators have access to lots of data (e.g., weather, load), they must manually synthesize data into useable information. This has worked well historically, but as the system changes the solution must envision a future with more complex information and less experienced operators. In the future, MISO Operations is looking to have an integrated toolset for operators that leverages artificial intelligence and machine learning. Techniques to improve how we see and navigate will give operators important information automatically.

OPERATIONS OF THE FUTURE ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Situational Awareness	• Advanced MISO visualization techniques • Intelligent alarming • Decision support systems leveraging artificial intelligence / machine learning	• Smart transmission technologies (e.g. ambient adjusted and dynamic line ratings) • Advance synchrophasor applications	• Real time display replacement	• Assessment of real-time displays and energy management displays to inform the visualization roadmap
Operations Planning	• Look-ahead commitment products • Predictive scenario analysis • Outage coordination changes	• Enhanced forecasting		• Dispatchable Intermittent Resources forecasting
Operations Preparedness	• Operations simulation • Reliability product testing			
Critical Communications	• Operations communications • Event/operator logging			

Market System Enhancements

MISO's ability to respond to the Reliability Imperative will be enabled through continued market system enhancements and modeling. Current systems and technology are not capable of meeting the new, reliability driven market improvements and fully leveraging new resources such as storage and distributed energy resources. Even minimal changes to the market systems today require significant resources. The new system will allow more timely improvements to meet MISO's evolving needs.

Today, MISO's legacy system has limitations. Recent upgrades (e.g., MISO's Private Cloud launched in July 2020) will help inform future investments. The Market System Enhancement, or MSE Program, was formed in 2017 to transform our current market platform into a more flexible and secure system. The work is ongoing, but already has reached important milestones including extending the life of legacy systems, improvements to the Energy Management System while the larger upgrade is in-flight, and launching the Readiness Application for the Market User Interface (which will go into production in 2021).

> "MISO's Market System Enhancement Program will provide the platform for faster adoption of new technologies into the market and better accommodate the region's changing resource mix to ensure reliable and efficient operations for our customers."
>
> Todd Ramey, VP and Chief Digital Officer

Building on the MSE Program progress, flexible design, advanced data analytics, and model management will help MISO to meet the Reliability Imperative. In contrast to the current legacy technology, the future market platform will integrate technology and systems to better utilize data. Modern architecture means systems that provide flexibility for the evolving needs of the business. Across the various workstreams of the Reliability Imperative, MISO is establishing a portfolio management function to ensure that investments align with the long-term strategy, including meeting the risks of the changing resource fleet.

MARKET SYSTEM ENHANCEMENT ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Market System Enhancement		• Real-Time Market Clearing Engine	• Market User Interface • Model manager / data governance • Energy Management System (EMS) Upgrade • Day-Ahead Market Clearing Engine	• MISO Private Cloud • Extend life of legacy system
Technology and Portfolio Needs	• Develop and deploy data analytics • External Self-service data • Module E Capacity Tracking (MECT) tool assessment	• Update the MISO Communication System (MCS)		

Connections Between the Workstreams

The work described here is organized across four main workstreams – market redefinition, long range transmission planning, operations of the future, and market system enhancements. These workstreams are connected and build on each other. Also, success in one area depends on progress in another, so efforts must be coordinated and sequenced.

For example, given the changing resource fleet, providing reliable and economically efficient grid operations requires both new tools and process being developed under the Operations of the Future workstream, and market enhancements being developed under the Market Redefinition workstream. Additionally, the ability to interconnect renewable resources may be constrained by the existing transmission system and therefore dependent on some of the changes being contemplated in LRTP. In a similar vein, the ability for MISO to deploy enhanced situational awareness depends on the quality of our data deployed through MSE.

By documenting our future vision in this report, and outlining next steps across the four main workstreams, MISO is starting an important dialog about how to prioritize different work efforts. As we continue to update this "living" document, we believe the Reliability Imperative will note dependencies and impacts of any future schedule changes. MISO plans to continue the dialog by updating stakeholder committees regularly on the Reliability Imperative.

The Opportunity: Capturing the Value

As described in this paper, MISO sees the challenges of the changing resource fleet. We are facing a Reliability Imperative to prepare for the future, and MISO is hard at work on a number of key planning, operational, and systems efforts.

The fleet change represents not just challenges, but also enormous opportunities for MISO to enable members, states, regulators, and consumers to meet their objectives reliably and affordably.

By listening and taking a system-wide view, MISO can help ensure that all stakeholders have the right information.

By helping forward planning, MISO will help members to develop generation and transmission portfolios that maintain system reliability without over-investing. As member portfolios materialize, MISO markets and operations will optimize energy across the footprint. In addition, MISO will continue coordinating with our neighboring seams partners.

MISO has delivered substantial value to its members since its creation, as demonstrated by the annual Value Proposition calculation. Going forward, additional sources of value will emerge through the sharing of attributes across the diverse resource fleets. MISO is in the early stages of investigating how to calculate these new sources of value in an evolved, future-looking Value Proposition. Given changes to fleet, grid, market, and operations, it is more important than ever that the MISO region work together so that each member continues to realize the substantial benefits of our regional structure.

> "MISO has the opportunity to help its States and Members reach their own policy goals in the most cost-effective way while also ensuring the reliable delivery of electricity to end-use customers."
>
> Wayne Schug, MISO VP Strategy & Business Development

Working Together to Address the Reliability Imperative

This is a report written from MISO's perspective. It lays out MISO's proposals to address the challenges associated with the region's changing resource mix. As an independent, FERC-approved system operator, MISO is responsible for the reliability of the Bulk Electric System and has the authority to act.

But the responsibility for the Reliability Imperative is certainly not MISO's alone. Utilities, electric cooperatives, and other load-serving entities serve the load and own the region's transmission lines, generating units, and other infrastructure. State regulatory agencies also play an important role in overseeing how load-serving entities carry out their responsibilities.

Internal and external input

While this report focuses on MISO's ideas and proposals, it was heavily informed by technical and policy-related input we received from our members and other entities described above. Much of that input came from the formal MISO stakeholder process and its committees, which have expertise in markets, operations, and planning. MISO also received input from industry trade groups, consultants, and other entities with insights into the challenges that are facing our region.

MISO is committed to working closely with its stakeholders as we identify, design, and implement the Reliability Imperative. We believe that by doing so, we can continue to operate the system reliably and efficiently while also working with the differing utility business models and state energy policies in our region.

A Message from Clair Moeller, President

Utilities, states, and other stakeholders in the MISO region differ widely in terms of their policy goals, business models, and other interests. MISO knows that not all stakeholders will support every view, recommendation, and initiative that MISO lays out in this report. Concerns are sure to be raised in the stakeholder process, and perhaps beyond it as well.

That's OK. That's how it should work. That's how important issues like these should be debated. Our region is facing some very difficult and complex challenges, and no single entity--MISO included—has the perspective, experience, and wisdom to fix them singlehandedly. Everyone should be invested in the outcome. Everyone should offer up their ideas and their proposed solutions.

This report represents MISO's initial contribution to that effort—but it does not represent the last word on the subject. MISO welcomes stakeholder feedback on the proposals described in these pages, and if stakeholders have different ideas altogether, we want to hear them. Will we agree on everything? No. But that should not—and must not—stop us from working together to meet the obligations of the Reliability Imperative.

We also recognize that we will need to adjust our approach going forward as industry conditions and the needs of our stakeholders continue to evolve. We are committed to working cooperatively with all of our stakeholder sectors to address these long-term challenges. In the meantime, we will continue to address incremental enhancements needed to maintain reliable and efficient operations.

This report is a current, snapshot-in-time look at how we see the Reliability Imperative today, but we will revise our approach as we learn more.

The time to act is now – the industry is changing, and MISO members are poised to drive exciting, necessary changes over the coming years. Given the regional Reliability Imperative, MISO must act quickly and deliberately to ensure that the planning, markets, operations, and systems keep pace with our members' plans.

Let's get to work,

April 30, 2021

Arkansas Energy Resources Planning Taskforce
Sent via email: ERPTaskForce@adeq.state.ar.us

Re: February 2021 Weather Event; Regional Transmission Organizations

Dear Taskforce Members:

Southwest Power Pool, Inc. ("SPP") appreciates the opportunity to provide the Arkansas Energy Resources Planning Taskforce ("ERP Taskforce") with information relating to the winter weather event that occurred on February 4, 2021, through February 20, 2021 ("February 2021 Weather Event"). SPP provides responses to the ERP Taskforce's questions below:

1. Having had some time to do an analysis of your operations since the February 2021 Weather Event, could your organization provide a brief summary of your role in addressing the power outages during the February winter event.

Response 1:

During a special meeting March 2, 2021, SPP's Board of Directors approved a plan to assess SPP's performance, and that of its members and market participants, during the February 2021 Weather Event. The newly formed Comprehensive Review Steering Committee is currently overseeing five teams comprising representatives of SPP staff, stakeholders, the SPP Market Monitoring Unit ("MMU")[1], and the SPP Regional State Committee[2] ("SPP RSC"). The five teams will evaluate operational, financial, communications and other factors related to the events of the February 2021 Weather Event. The group will provide its final

1 SPP's Market Monitor is responsible for monitoring SPP's Markets and services. The group's primary purpose is to ensure SPP's markets are efficient and fair. Specific duties include: Obtaining objective information about SPP's markets and services; Assessing the behavior of Market Participants (MPs); and Assessing the behavior of other markets and services that impact SPP.

2 The SPP RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission and is comprised of retail regulatory commissioners from agencies in Arkansas, Iowa, Kansas, Louisiana, Missouri, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota and Texas.

assessment and recommendations at the July 27, 2021 meeting of the SPP Board of Directors and Members Committee. The Midwest Reliability Organization ("MRO")[3], the Federal Energy Regulatory Commission ("FERC")[4], and the North American Energy Reliability Corporation ("NERC")[5] are conducting separate, independent assessments in which SPP will participate.

Section 215 of the Federal Power Act[6] requires that NERC develop mandatory and enforceable Reliability Standards, which are subject to FERC review and approval. FERC-approved Reliability Standards provide minimum requirements for reliable operation of the bulk electric system ("BES")[7]. SPP as the Balancing Authority[8] and Regional Coordinator[9] for the SPP footprint is bound by applicable Reliability Standards, and SPP is subject to FERC's enforcement jurisdiction for compliance with these Reliability Standards.

2. Did your existing emergency procedures work as intended and are there any improvements you will be implementing to deal with similar power shortages due to potential future events?

Response 2:

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[3] MRO's primary responsibilities are to: ensure compliance with mandatory Reliability Standards by entities who own, operate, or use the interconnected, international BPS; conduct assessments of the grid's ability to meet electricity demand in the region; and analyze regional system events.

[4] FERC is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity, which includes SPP.

[5] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel.

[6] 16 U.S. Code § 824o.

[7] BES means the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100kV or higher.

[8] A Balancing Authority integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

[9] A Reliability Coordinator is responsible for the Reliable Operation of the BES and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.

SPP's existing emergency procedures[10] worked as expected during the February 2021 Weather Event. As you are aware, the February 2021 Weather Event produced extremely cold temperatures across the entire SPP service territory. This led to increased electricity usage at the same time generation resources experienced reduced ability to produce energy, as a result of a multitude of reasons. In collaboration with its member utilities and neighboring grid operators, SPP limited the storms' reliability impacts to two periods of controlled service interruptions: one on February 15, 2021, for 57 minutes to reduce regional energy use by approximately 1.5% and one on February 16, 2021, for three hours and 23 minutes to reduce regional energy use by approximately 6.5%. These actions prevented longer, uncontrolled, more widespread and costly blackouts.

Although, SPP's emergency procedures worked as intended during the February 2021 Weather Event, SPP is committed to learning from this event and identifying improvements that can better facilitate future emergency responses. SPP will implement any approved recommendations from the Comprehensive Review Steering Committee in order strengthen our emergency response procedures and to help minimize service interruptions in the future.

3. Unlike the events in Texas, as discussed in your testimony to the Energy Committees, the larger multi-state system operated by SPP and MISO appeared to be a reason the power outages in Arkansas were not as extensive.
   - Describe your preparedness and allocation process for critical energy resources during extreme events.
   - Could you elaborate on why that structure was beneficial and how the two System Operators worked together to minimize the outages in Arkansas.

Response 3(a):

During the February Weather Event, SPP entered into multiple different operating levels/alerts as defined by SPP's operating plans and the NERC Emergency Operations and Planning ("EOP") Standard 011-1. Table A gives an overview of those operating levels:

10 SPP's emergency response plan details actions that are to be taken by SPP as the Balancing Authority and Reliability Coordinator for those applicable regional footprints. SPP's members are responsible for developing and executing their own emergency response plans applicable to the functions they perform and the parts of the transmission system under their purview.

Table A: Balancing Authority Operating Levels

BALANCING AUTHORITY (BA) OPERATING LEVELS

Levels/alerts defined by SPP operating plans

Normal Operations	SPP has enough generation to meet demand, has available reserves and does not foresee extreme or abnormal reliability threats
Weather alert	SPP expects extreme weather in its reliability coordination service territory
Resource alert	SPP's BA area expects severe weather conditions, significant outages, wind-forecast uncertainty and/or load-forecast uncertainty with potential to impact total capacity.
Conservative Operations	SPP determines the need to operate system conservatively to avoid an emergency based on weather, environmental, operational, terrorist, cyber or other events
Maximum emergency generation notification	SPP foresees the need to use emergency ranges of resources for a certain hours.

Levels defined* by NERC EOP-011-1

Energy Emergency Alert (EEA) Level 1	**All available generation resources in use** • All generation is committed, and there is concern about maintaining required reserves for BA • Non-firm wholesale energy sales curtailed.
EEA Level 2	**Load management procedures in effect** • BA is no longer able to provide its expected energy requirements and is energy deficient • Operating plan implemented, including public appeals and demand response • BA is still able to maintain minimum reserves • Market participants and other BAs notified • Transmission limitations evaluated and revised • BA makes use of all available resources
EEA Level 3	**Firm load interruption imminent or in progress** • BA is unable to meet minimum contingency reserve requirements • System & reliability limits revaluated and revised • Immediate action taken to mitigate undue risk to the Interconnection, including load shedding.

In anticipation of extreme winter weather and with the goal of preparing to ensure continued reliability, SPP issued early warnings including a cold weather alert on February 4th and a resource alert on February 8th. On February 9, 2021, SPP issued a conservative operations notice which remained in effect through February 20, 2021. On February 11 through February 16, 2021, SPP committed resources in the Day-Ahead Market ("DAM") using the Multi-Day Reliability Assessment ("MDRA") process for Operating Days on February 13, 2021, through February 18, 2021, to ensure resources were on notice that they would be needed during this time.

Ordinarily, SPP commits "long lead time" resources that have three to four day start times, i.e., resources that could not be committed in the Day-Ahead Reliability Unit Commitment Process (RUC)[11], through the MDRA process. However, during this conservative operations period, in the interest of reliability and in accordance with the SPP Open Access Transmission Tariff ("Tariff"), SPP committed both long-lead time and a number of non-long-lead time resources through the MDRA. This forward commitment gave resources as much advance notice as possible to procure fuel and prepare for the more extreme operating conditions forecasted to materialize

11 RUC is SPP's process to assess resource and operating reserve adequacy for the operating day, commit and/or de-commit resources as necessary, and communicate resource commitments or de-commitments to the appropriate Market Participants, as necessary.

on February 15, 2021 and expected to continue throughout the early part of that week.

On Sunday, February 14th, SPP issued an Energy Emergency Alert Level 1 and asked its member companies to begin issuance of public appeals for conservation. SPP did this in anticipation of increased electricity consumption and tightening supply concerns beginning on February 15th.

There were two periods during the February 2021 Weather Event where SPP directed its member utilities to curtail energy use to bring regional supply and demand back in balance. The first period was on February 15th at 12:04 p.m. Central time, where SPP directed our Transmission Operator ("TOP")[12] members reduce regional energy use by approximately 1.5%. This first demand interruption lasted for approximately 57 minutes before system conditions allowed SPP to restore all load. The second period was on February 16th at 6:44 a.m., where SPP directed our TOP members reduce regional energy use by approximately 6.5%. This demand interruption lasted until 10:07 a.m. In both cases, the SPP operators had declared an Energy Emergency Alert Level 3 prior to issuance of load shedding directions, signaling to our members that we did not have enough generation to serve load and maintain operating reserves and indicating that required interruptions of service might follow. Each TOP operating in the SPP Balancing Authority Area was required to curtail its energy use by a predetermined pro-rata percentage of SPP's total required regional reduction of energy use.

When TOPs are directed to curtail energy use, SPP only specifies the amount by which each member utility must decrease their load. SPP cannot, and does not, specify how the reduction of energy use should be accomplished. Rather, each TOP follows its own emergency operating plan and makes decisions regarding what residential, commercial, or industrial load to curtail. SPP directs these controlled service interruptions only as a last resort when they are necessary to prevent uncontrolled outages from occurring as a result of inaction.

Coordination and communication between SPP and other entities during an emergency event is outlined in the SPP Balancing Authority Emergency Operating Plan ("SPP BA EOP").[13] Specifically, Section 7 of the SPP BA EOP outlines coordination and communication responsibilities during Energy Emergency Alerts, which were utilized by SPP during the February 2021 Winter Event.

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12 The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

13 SPP Balancing Authority Emergency Operating Plan: https://spp.org/documents/63143/spp%20ba%20emergency%20operating%20plan_v%207.5.pdf

Response 3(b):

SPP oversees a regional, multi-state transmission grid, with diverse generation located across its 14-state footprint in the Eastern Interconnection and strong transmission interconnections with its neighbors. As compared to transmission and generation located in just one state with limited transmission interconnections to other areas, SPP has increased ability during an emergency to rely on all generation in its entire footprint and energy transfers from neighboring areas to mitigate supply deficiencies. Similarly, SPP is more able to share its excess generation with neighboring Transmission Providers, such as MISO, to assist their efforts to operate reliably during severe weather events. During the February 2021 Weather Event, SPP received significant amounts of energy from MISO and other neighboring regions that helped minimize reliability impacts. SPP received up to approximately 6,000 MW of energy from its neighbors at certain critical times during the event.

4. As outlined in your testimony to the Energy Committee, the System Operators cooperated to provide assistance as necessary to assist the other System.
   - Were communication protocols in place prior to the February event for the System Operators to provide mutual assistance?
   - If not formal protocols, are their plans to establish more formal procedures between the System Operators in the future?

Response 4:

Yes, SPP has joint coordination/operating agreements among all of its neighboring system operators that detail communication protocols between each entity. Specifically, the following are the joint coordination agreements among SPP and its neighboring system operators: (1) Joint Operating Agreement Between MISO and SPP;[14] (2) SPP-Associated Electric Cooperative, Inc. ("AECI") Transmission Coordination Agreement;[15] (3) SPP-AECI Joint Operating Agreement;[16] (4) SPP-ERCOT Coordination Plan;[17] (5) Joint Operating Agreement between SPP and

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14 MISO-SPP Joint Operating Agreement is required to be filed and approved by FERC. See the following: https://www.spp.org/documents/37691/2016-04-07%20spp-miso%20joa.pdf.

15 https://www.spp.org/documents/5100/aeci%20transmission%20coordination%20agreement%2081904.pdf.

16 https://www.spp.org/documents/8373/aeci%20spp%20joa%20final%20signed%2008-12-08.pdf.

17 https://www.spp.org/documents/62411/ercot-spp%20coordination%20plan_20200601.pdf.

Saskatchewan Power Corporation;[18] and (6) SPP-Tennessee Valley Authority Adjacent Reliability Coordinator Coordination Agreement.[19]

Current agreements and protocols between SPP and its neighboring systems and any needed improvements are being considered in the comprehensive review currently being performed.

5. Given that communication between the System Operators is important, it is equally important to communicate with the public and affected parties of pending outages necessary to maintain the System.
   - Were the notification procedures in place at the time of the February event sufficient? What improvements to a notification process should be made?
   - When outages are necessary, who makes the determination which areas are required to shed load?
   - Are there protocols in place for determining which areas are chosen to shed load and/or consideration given to the types of facilities impacted?
   - Is there sufficient usage data to adequately determine the impact of outages in each area or on different types of infrastructure or facilities in those areas?
   - How does the end user appeal or request consideration of unique circumstances upon notification of service curtailment?

Response 5 (a):

Coordination and communication between SPP and other operating entities during an emergency event is outlined in the SPP BA EOP.[20] Specifically, Section 7 of the SPP BA EOP outlines coordination and communication responsibilities during Energy Emergency Alerts, which were effectively utilized by SPP during the February 2021 Winter Event. SPP also deployed various means of communicating with its stakeholders prior to and during the event through both written and verbal communications. Additionally, SPP held virtual meetings with public relations staff employed by member companies as well as press conferences for media.

Despite these efforts and the efforts of our member companies to communicate as effectively as we could, we understand that one of the biggest frustrations voiced

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[18] https://www.spp.org/documents/36511/2015-10-01_spp-saskatchewan%20power%20corporation%20joa.pdf.

[19] https://www.spp.org/documents/6157/tva%20rc%20coordination%20agreement.0506.pdf.

[20] SPP BA Emergency Operating Plan: https://spp.org/documents/63143/spp%20ba%20emergency%20operating%20plan_v%207.5.pdf

by many in the general public related to a desire for more proactive and effective communications. As stated in Response 1, above, the newly formed Comprehensive Review Steering Committee is evaluating operational, financial, communications and other factors related to the events of the February 2021 Weather Event. The group will present an update on early findings at the April 27, 2021 meeting of the SPP Board of Directors and Members Committee and provide its final assessment and recommendations at the July 27, 2021 meeting of the SPP Board of Directors and Members Committee.

Response 5(b):

SPP makes the determination of which TOPs must shed load and how much load must be shed to relieve a system contingency. The TOPs then determine how to achieve the load shedding obligation placed on them by SPP in accordance with their plans. The determination of need to shed firm load only happens when all other possible means of suppling the internal SPP Balancing Authority load have been used to address an emergency within the SPP Balancing Authority Area so as not to jeopardize the reliability of the Bulk Electric System.

Response 5(c):

Yes, protocols are in place in the form of emergency response plans that are required by NERC to be developed, maintained and practiced annually. SPP's plans address its role in responding to an emergency from a regional perspective. When SPP experiences an emergency related to lack of energy needed to supply regional demand, it allocates load shedding requirements among all TOPs. When SPP experiences an emergency related to specific transmission elements, load shedding requirements are confined to those TOPs necessary to resolve the transmission-related emergency. As stated previously in Response 3(a) above, when SPP directs TOPs to curtail energy use, SPP only specifies the amount by which each TOP must decrease its load. SPP cannot, and does not, specify which end-use customers should be affected by the required reduction of energy use. Rather, each TOP follows its own emergency operating plan and makes decisions regarding what residential, commercial, or industrial load to curtail.

Response 5 (d):

SPP has the necessary data to effectuate its obligations from a regional perspective. SPP relies on the TOPs to manage their load shedding procedures including determinations of loads and customers' priorities and the infrastructure or facilities impacted. SPP does not have the level of detailed usage data to determine what impacts any load shedding event may have on TOPs' areas or distribution-level infrastructure and facilities in those areas.

Response 5(e):

As stated in Response 5(b), SPP's determination of the need to shed firm load only happens when all other possible means of suppling the internal SPP Balancing Authority load have been used to address an emergency within the SPP Balancing Authority Area so as not to jeopardize the reliability of the Bulk Electric System. Pursuant to the SPP BA EOP, participating entities within the SPP Balancing Authority Area shall have plans for how they will shed load to respond to real-time emergencies. Because firm load shed events only happen when other possible means of serving load have been used to address an emergency, it is not possible for SPP to allow participating entities to appeal or request consideration of unique circumstances to relieve them of their obligations to load shed. Any such appeals or special considerations between those participating entities and certain end-use customers would need to occur within the framework of their respective plans and protocols.

6. Are there changes that integrated system operators need to consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event?

- If so, what changes would you recommend?
- Are there constraints in place from Federal Energy Regulatory Commission or North American Electric Reliability Corporation that would prevent implementation of such changes?

Response 6(a):

At present, SPP does not have enough pump storage or battery storage in the SPP footprint that would have affected the impacts of the 2021 Weather Event on the SPP transmission system. During the 2021 Weather Event, all available generation was required (and even then, there was a two brief curtailments of energy use needed). SPP did not have the generation available, once the event was forecast, solely for storage purposes.

Electricity storage presents a potential mitigation option in addressing the unpredictability of renewable-sourced generation by allowing excess electricity production to be captured and used at a later date and time. To be effective, however, investments in such storage would need to be large-scale. Within SPP, this type of investment would be made by independent entities or vertically integrated utilities and not under the direction from SPP.

Moving forward, the usage of storage should not exclusively be considered only from a capacity perspective, but storage should also be considered from a duration of time perspective for when the storage is available. Most battery storage is being developed and accredited for 4-hour delivery of power, however, using the 2021 Weather Event as an example, 4-hour storage capacity would have been exhausted very early on during the event. For storage to make a significant impact on the grid in future weather events, SPP will need both more capacity and a longer duration of time the storage is available.

Response 6(b):

SPP does not have any recommended changes, at this time, in processes to allow for increasing generation for the purposes of holding electricity in storage in advance of a forecasted extreme weather event.

Response 6(c):

SPP is not aware of any FERC or NERC constraints that would prevent implementation of such changes.

SPP appreciates the opportunity to respond to the questions from the ERP Taskforce. Please contact me if there is further information that you may need.

Sincerely,

Lanny Nickell
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Arkansas Environmental Federation
Industries for the Environment

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Energy Resources Planning Task Force
Attn: Secretary Becky Keogh, Chair
Arkansas Department of Energy and Environment
5301 Northshore Drive
North Little Rock, AR 72118

Delivered via electronic mail to ERPTaskForce@adeq.state.ar.us

Dear Secretary Keogh,

The Arkansas Environmental Federation (AEF) is pleased at the call to participate in the Energy Resources Planning Task Force. Members of AEF range from sole proprietorships to international corporations with manufacturing facilities throughout the state. As the preeminent environmental organization serving industry in Arkansas, the AEF is pleased our Governor appointed this Task Force to review lessons learned from unprecedented winter weather and develop priorities should we face this type of emergency again.

The questions the AEF received April 12, 2021, were circulated to members for response. Member responses varied greatly depending on company size and type. Below is a compilation summary of the responses received.

1. Do Arkansas business owners or industries in Arkansas whose facilities were asked to curtail operations during the February weather event feel they were treated fairly and given adequate notice? Would you suggest any changes to prioritization of gas and electricity or communications regarding extreme weather events? If so, what changes would you make?

The consensus of the answers received by AEF demonstrate the need for earlier and more detailed notice.

2. Did the curtailment during the load-shedding event damage or reduce the effectiveness of environmental quality control equipment? What strategies could have been implemented to mitigate the impacts of curtailment and the extreme cold on control equipment?

No, the majority of responses submitted answered no. Those that did answer yes to damage believe adequate notice and minimum utility requirements are needed to mitigate equipment damage.

3. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

The unanimous answer to this question is no suggestions.

4. Describe your preparedness and allocation process for critical energy resources during extreme events.

Responses to this question mainly illustrates significant challenges to allocate energy resources during extreme events.

5. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Answers to this question were mostly split between negotiation with provider or inability to appeal or request consideration.

The answers we received represent less than 5% of AEF member companies. An extension of time to submit this questionnaire may allow companies more time to answer the questionnaire.

Sincerely,

Ava F. Roberts

Ava F. Roberts
Executive Director
Arkansas Environmental Federation

318 South Pulaski Street
Little Rock, AR 72201
501-372-4500

To: Arkansas Energy Resources Planning Task Force

Date: May 7, 2021

Via: Hand Delivery and *ERPTaskforce@adeq.state.ar.us*

Re: Hearing Testimony regarding February 2021 Winter Weather Event

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Initial Hearing Testimony

Introduction and Reservations:

The Arkansas Forest and Paper Council (AFPC) appreciates the opportunity to provide testimony to the Arkansas Energy Resources Planning Taskforce (Taskforce) on the extreme weather event of February 2021 and the significant impact the weather and resulting energy curtailments had upon the forest and paper industry in Arkansas. These comments are provided via electronic mail and hand delivery of paper copies for the convenience of the Taskforce.

The Arkansas Forest and Paper Council is a 501(c)6 trade organization representing the forest products manufacturing industry in the state of Arkansas. Our members manufacture paper and consumer products as well as building materials utilized in 95% of all business and 100% of households in the US. The industry in Arkansas has 95 facilities employing more than 19,000 direct employees with a $1.3 billion dollar payroll producing $7.6 billion dollars of product from our rich fiber basin. The economic contributions to communities and schools across the state through purchases of goods and services and taxes paid are varied and wide.

The access to reliable and affordable energy is crucial to the efficient and cost-effective operation of the forest products and manufacturing industry in Arkansas – and this is never more true than during extreme weather events. The work of the Taskforce and the related inquiries and reviews underway at the Arkansas Public Service Commission (APSC), the Federal Energy Regulatory Commission (FERC), the Regional Transmission Organizations (RTOs) and their Independent Monitors (IM), the Attorney General, among others present an opportunity for the regulators and regulated community to assess the unprecedented winter weather event of February 2021 (the WWE) and the tremendous costs and losses that resulted, and to do so with an eye towards creating an energy system that is more robust, cost-effective, and reliable to the benefit of all energy users and the communities they support.

The AFPC is uniquely situated to provide perspective on these matters given the wide impact the industry has within Arkansas. This is evident in part by the fact that its membership has facilities served by both the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO), and variously Entergy, AECC, and SWEPCO as well as receiving gas service via the Enable system and the various FERC related pipelines within Arkansas – many of which have been requested to provide testimony in the Taskforce's work.

While the AFPC provides this testimony voluntarily, it does so with several reservations. First, the Taskforce requested the AFPC respond to the following questions for the Energy Users group. Each question will be responded to in turn, repeating each question for clarity and convenience - and to the extent this issue is adequately covered by others providing testimony, the AFPC attempts to refer to that testimony. In these instances, the other testimony will be noted in the relevant question / response.

In response to each and every question and statement in response without waiver of any defense or privilege that it or its members may be entitled to claim individually or collectively, including without limit that under the Arkansas Trade Secrets Act, Arkansas Water and Air Pollution Control Act, and any others applicable to these matters. Also, the testimony is that of the AFPC, an incorporated association, and no particular statement or position should be attributed to any particular AFPC member or industry representative.

As to future proceedings of the Taskforce, the AFPC respectfully requests it be provided additional opportunity to meet with the Taskforce and other stakeholders, review the other testimonies filed with the Taskforce, and provide additional other information, if necessary.

Should the Taskforce have additional questions for the AFPC, please contact either Brent Stevenson at brent@brentstevensonassociates.com or 501-372-4500 or Kelly McQueen at kelly@mcqueen.law or (501) 580-3291.

Questions Presented

Question 1: Do Arkansas business owners or industries in Arkansas whose facilities were asked to curtail operations during the February weather event feel they were treated fairly and given adequate notice? Would you suggest any changes to the prioritization of gas and electricity or communications regarding extreme weather events? If so, what changes would you make?

Response:

Along with many others in manufacturing and industry that have expressed concerns with the February event's impacts as well as the deficiencies in the curtailment process and the resulting costs and losses, the forestry and paper industry also experienced increased costs and losses associated with the extreme weather event. Notably, all Council members experienced a curtailment, with most receiving sufficient notice from the supplier with enough time to make their individual business decision. However, the costs and losses even with adequate notice – depending on the situation – were significant, numbering in the tens of millions of dollars ($) from equipment damage, additional energy costs, production losses, increased manhours, among other costs and losses.

The AFPC refers the Taskforce to the testimony of Mr. Ted Thomas, Chairman of APSC regarding background on the winter weather event (WWE), its potential causes, and the various reviews underway related to the WWE. The APSC testimony as well as that of the Attorney General, AEEC, and numerous others provide a good overview of the winter weather impacts on downstream natural gas customers, the curtailment process and FERC managed special needs waiver process for exemption from curtailment to the extent necessary to protect a designated special need – so the AFPC will not attempt to provide an additional source of the same information.

However, the AFPC would like to highlight a number of suggestions and recommendations for the Taskforce's review, reserving the right to provide additional information and recommendations as this matter develops:

1. Other Reviews:
    a. Many of these matters appear to be under the jurisdiction of the FERC with limited opportunities for state regulation or revision. The State should participate fully in any related FERC dockets.
    b. The APSC has opened a docket for review of the WWE in which the AFPC intends to participate.
    c. The AFPC supports review of market price fluctuations.
    d. The AFPC supports the RTO review processes currently underway.

2. Rate / Tariff Design:
    a. APSC and state utilities should design interruptible tariffs reflective of cost-to-serve, with appropriate price signals, and compensation for the value interruptible customers provide the system.
    b. Promotion of progressive interruptible tariffs, with appropriate compensation and price signals, to encourage more emergency demand response participation should be considered.
3. Reserve Margin: each RTO should have a reliable, reasonable, and dispatchable reserve margin with sufficient capacity to meet swing loads and peak capacity demands.

4. Affidavits of Special Need:
    a. The definition of special needs should be expanded to provide sufficient protection for human health and plant protection,
    b. Education of availability of Affidavits and curtailment process generally should be required of distribution and transmission service companies.
    c. Timing of filing of Affidavits should be flexible enough for submittal after beginning of curtailment.

5. Federal-Local Partnership: to the extent possible, the interstate FERC mandated pipeline rules and those governing the local distribution should not conflict.

6. Communications: Explore all means to facilitate more effective communications in extreme weather events or other energy disruptions including review of additional lines and modes of communication between providers and users with specified requirements for updates related to price / supply / other necessary metrics to be developed.

Question 2: Did the curtailment during the load-shedding event damage or reduce the effectiveness of environmental quality control equipment? What strategies could have been implemented to mitigate the impacts of curtailment and the extreme cold on control equipment?

Response:

Across industry of all sorts, extreme weather events and any energy disruptions may have an impact on the effectiveness and even operation of pollution control equipment. The Environmental Protection Agency (EPA) for federal programs and the Arkansas Division of Environmental Quality (ADEQ), as implementing the Arkansas Pollution Control and Ecology Commission (APC&EC) regulations and related federal EPA requirements has procedures for how to proceed in the event this occurs.

<u>Question 3</u>: Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

<u>Response</u>:

The AFPC does not have information on which entities currently have been requested to provide testimony. Based upon the Executive Order, the AFPC respectfully suggests that testimony from the Attorney General, ENABLE Midstream Partners, and other manufacturing related entities may provide additional information benefiting the Taskforce's review and report.

<u>Question 4</u>: Describe your preparedness and allocation process for critical energy resources during extreme events.

<u>Response:</u>

As an association, the AFPC does not have preparedness or allocation processes for critical resources during extreme events. Speaking generally, facilities within the industry routinely have standard operating procedures in place for inclement weather conditions and implement these procedures during such occurrences.

<u>Question 5</u>: Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

<u>Response:</u>

Please see Response to Question 4.

To:	**Arkansas Energy Resources Planning Task Force**
From:	**Tinsley & Youngdahl, LLC, Attorneys for AEEC and AGC**
Date:	**May 7, 2021**
Via:	**Email to ERPTaskforce@adeq.state.ar.us**
Re:	**Hearing Testimony on February 2021 Winter Weather Event**

Initial Hearing Testimony

Introduction and Reservations:

Arkansas Electric Energy Consumers, Inc. (AEEC) and Arkansas Gas Consumers, Inc. (AGC) appreciate the opportunity to provide testimony to the Arkansas Energy Resources Planning Task Force (Task Force) on the extreme weather event of February 2021 and the significant impact the weather and resulting energy curtailments had upon industrial and agricultural business concerns in Arkansas. AEEC is an incorporated trade association that represents the interests of several large users of electricity in Arkansas, and AGC is an incorporated trade association that represents the interests of several large users of natural gas in Arkansas. The access to reliable and low-cost energy is crucial to the efficient and cost-effective operation of large businesses in Arkansas – and this is never more true than during extreme weather events. The work of the Task Force, together with related inquiries and reviews underway at the Federal Energy Regulatory Commission (FERC), the Arkansas Public Service Commission (APSC), Regional Transmission Organizations (RTOs) and their Independent Monitors (IM), and the

Attorney General (among others), present an opportunity for regulators and regulated community to assess wisely the unprecedented winter weather event of February 2021 (the WWE) and the tremendous costs and losses that resulted, and to do so with an eye towards creating an energy system that is more robust, cost-effective, and reliable to the benefit of all energy users and the communities they support. AEEC and AGC members primarily have facilities served by the Midcontinent Independent System Operator (MISO) and its member Entergy Arkansas, LLC, as well as members receiving natural gas service via the Enable system and the various FERC related pipelines within Arkansas – many of which have been requested to provide testimony in the Task Force's work.

While AEEC and AGC provide this testimony voluntarily, they do so with several reservations. First, AEEC and AGC are responding to the following questions asked of the Energy Users group. Each and every statement in response should not be construed as a waiver of any defense or privilege that it or its members may be entitled to claim individually or collectively, including (without limitation) any defense or privilege arising under the Arkansas Trade Secrets Act, Arkansas Water and Air Pollution Control Act, and any other laws or regulations applicable to these matters. Also, the testimony is that of AEEC and AGC, two incorporated trade associations, and no particular statement or position should be attributed to any particular AEEC or AGC member or industry representative. As to future proceedings of the Task Force, AEEC and AGC respectfully request that they be provided additional opportunity to meet with the Task Force and other stakeholders, review the other testimonies filed with the Task Force, and provide additional information, if necessary. Should the Task Force have additional questions for AEEC or AGC, please contact Steven Cousins (stevencousins@outlook.com), Jordan Tinsley of Tinsley & Youngdahl, PLLC (Jordan@TYattorney.com).

AEEC and AGC Responses to ERPTF Questions to Energy Users:

1. Do Arkansas business owners or industries in Arkansas whose facilities were asked to curtail operations during the February weather event feel they were treated fairly and given adequate notice? Would you suggest any changes to the prioritization of gas and electricity or communications regarding extreme weather events? If so, what changes would you make?

While AEEC is an incorporated trade association that represents the interests of several large users of electricity in Arkansas, it cannot reveal any customer-specific information in response to these questions. AEEC can only speak generally about how the winter events impacted large customers, and what best practices should be. Many industrial and agricultural customers take electric service on interruptible tariffs, which means they can be subject to curtailment in the event that the utility's peak load has exceeded the available capacity. In exchange for their agreement to be interruptible, those customers receive a discount on rates. February's events amply demonstrated that the existence and availability of interruptible customers provides substantial benefits to the utility, its grid, and other ratepayers. To the extent that the state's electric utilities largely complied with the notice provisions contained in their respective interruptible tariffs during February's events, it is difficult to say that the electric utilities did not provide adequate notice of the interruptions that occurred. Regulators should take note of the effectiveness of those interruptible tariffs, however, and think twice before making any changes that could impair the economics of interruptible tariffs for large customers. To the extent they are not already doing so, the APSC and state utilities should design interruptible tariffs reflective of cost-to-serve, with appropriate price signals, and provide sufficient compensation for the value interruptible customers provide the system, and promote progressive interruptible tariffs, with appropriate compensation and price signals, to encourage more emergency demand response participation.

Further, large customers' operations are very sensitive to fuel and purchased power costs, which are passed through to all customers. Therefore, two communications issues should be prioritized: First, to the extent a customer is to be curtailed, the utility should provide notice as soon in advance as possible, to enable the business to change its operations as necessary to minimize the disruption and additional costs to its operations; second, any significant increases in energy costs need to be communicated to the business as soon as possible, so that the business can determine whether it is in its best interest to reduce or shut down operations (except the minimum necessary to keep its equipment from freezing) in view of these price spikes.

Similarly, while AGC is an incorporated trade association that represents the interests of several large users of natural gas in Arkansas, it cannot reveal any customer-specific information in response to these questions, and can only speak generally about how the winter events impacted large customers, and what best practices should be. Many large customers are gas transportation customers, which means they purchase gas directly from upstream suppliers, which they then transport through the gas pipelines, either through contracts at a fixed rate, or through contracts whose rate may fluctuate with spot market prices. The gas supply market also features managers and schedulers in addition to the pipelines and end users. In cases where there are reduced gas supplies in winter, some pipelines may reduce load by reducing the flow of gas to a transportation customer to the minimum amount necessary to keep its equipment from freezing, provided that the customer has a special needs and/or plant protection affidavit on file with the pipeline. When a customer does not have such an affidavit on file, that customer bears the risk of either (a) being completely shut off from gas, potentially causing damage to equipment due to the extreme cold; or (b) incurring substantial penalties for burning gas during a curtailment event. Thus, it is important for market participants to educate end users about the need to have these affidavits on file, and when a major winter event is approaching, to give the customers adequate and timely reminders that these affidavits need to be executed and filed. Further, as is the case for electricity customers, significant increases in energy costs need to be timely communicated to the business, so that the business (especially one whose price fluctuates with the market) can determine whether it is in its best interest to reduce or shut down operations (except the minimum necessary to keep its equipment from freezing) in view of these price spikes.

The feedback that AEEC and AGC have received from their members after February's events suggests that many large industrial and agricultural customers were not aware of the requirement that they maintain plant protection and/or special needs affidavits on file with the gas pipeline through which they transport gas, although some customers were aware of that requirement. In light of that, the pipeline companies and other market participants should do more to educate customers about those requirements well in advance of events like this. In many cases, customers did not become aware of that requirement until it was too late to file the affidavit, insofar as the pipeline company requires it to be filed before the curtailment event. Moreover, many of the large end user companies have personnel managing their gas and electricity supply who also have substantial other responsibilities. Providing those individuals with short notice within which to perform certain tasks is typically not effective, insofar as the personnel are typically involved in lots of activity to prepare for an event of this nature, and their attention is necessarily divided. Thus, the pipeline companies should also consider allowing customers to file those plant protection/special needs affidavits for a period of time after a curtailment begins. Moreover, regulators should consider requiring some market participants (like suppliers, managers and schedulers) to provide end users with regular updates regarding spot market gas prices or even the price of kWh in the RTO day-ahead markets.

2. Did the curtailment during the load-shedding event damage or reduce the effectiveness of environmental quality control equipment?

What strategies could have been implemented to mitigate the impacts of curtailment and the extreme cold on control equipment?

Again, neither AEEC nor AGC can reveal any customer-specific information in response to these questions. We can point out, however, that environmental quality control equipment, like any other equipment in a factory or agricultural operation, can be damaged by extreme cold. Therefore, the best practices discussed in response to Question no. 1 which would minimize the possibility of plants being totally without heat and their equipment being damaged as a consequence also apply to minimize the possibility of damage to environmental quality control equipment.

3. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

As noted above, we have answered these questions on behalf of AGC, even though the Executive Order only included AEEC. Other natural gas consumers besides AGC could also provide potentially useful information to the Task Force.

Further, AEEC and AGC could provide some suggestions to the Task Force in response to questions that were posed to other groups. For example:

- **ELECTRIC UTILITIES Question No. 1:**
  - The prices charged at wholesale in the spot energy market are regulated by the Federal Energy Regulatory Commission (FERC). The State should, however, participate fully in any related FERC dockets and/or file a

complaint with FERC regarding these matters. Arkansas can push FERC to investigate possible manipulation of some prices in MISO and SPP during the February events, to assure that Arkansas End Users receive relief from higher energy prices that resulted from market manipulation.

- **ELECTRIC UTILITIES Question No. 3:**
  - AEEC maintains that one of the best hedges against energy price spikes is a diverse mix of electric generation capacity, so that one event, be it weather-related or otherwise, does not have an extreme impact on energy prices. This needs to be considered in planning future generation, and in decisions about plant retirements.
- **ELECTRIC UTILITIES Question No. 4:**
  - AEEC agrees that storage solutions for electricity should be explored, especially when coupled with solar energy. It is important in exploring these solutions that costs, as well as benefits, be included in any analysis, however.
- **NATURAL GAS PRODUCERS AND SUPPLIERS Question No. 1:**
  - AGC contends that encouraging and investing in pipeline diversity will significantly reduce the risk that future winter-weather events could result in gas shortages and curtailments; the more sources of gas supply, both in terms of geography and gas suppliers, the less chance that one event will detrimentally impact supply.

4. Describe your preparedness and allocation process for critical energy resources during extreme events.

AEEC and AGC incorporate the response to Question no. 1 above for reference. As noted in that response, they cannot reveal any customer-specific information in response to these questions.

5. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

As for Question no. 4, AEEC and AGC incorporate the response to Question no. 1 above for reference. As noted in that response, they cannot reveal any customer-specific information in response to these questions.

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April 30, 2021

Via Email: Troy.Deal@adeq.state.ar.us

Secretary Becky W. Keough
Cabinet Secretary, Arkansas Energy & Environment
Chair, Energy Resources Planning Task Force

Secretary Keogh:

I was honored to receive your April 9, 2021, request on behalf of Governor Asa Hutchinson's Energy Resources Planning Task Force ("the Task Force") to submit written comments in response to the Testimony Questions sent to "Energy Users" and "Electric Utilities." My firm, Quattlebaum, Grooms & Tull, PLLC, is privileged to represent clients in both groups. To be clear, my responses today are my own based on my experience advising clients during the February winter storms and in the weeks that followed, as well as my personal assessment of publicly-available statements in the media, journals, and other trade publications issued in the wake of the February storms. I hope the comments below are of some assistance to the Task Force as it performs its important work.

ENERGY USERS & ELECTRIC UTILITIES

From my perspective, the State of Arkansas's executive branch performed admirably during the February winter storms. State employees from your office, the Arkansas Department of Energy and Environment, Department of Environmental Quality ("DEQ") as well as the Arkansas Public Service Commission ("APSC") and other agencies were very responsive to energy and environmental-related concerns during the February winter storms. Arkansans should be proud of their willingness to work hard and think creatively to ensure the public was protected despite the adverse weather conditions.

The storms' consequences were severe from both a human and economic perspective. Arkansas is fortunate that the severe weather did not last longer here and that it was not even colder than it was. This experience has made it clear that it would be helpful if Arkansas's key regulators were given more legal tools to coordinate on resource distribution or even intervene directly in the future if a temporary emergency implicating public safety requires it. This would require new statutory authority. As the Task Force considers what new authority should be recommended, it may want to consider the following:

- DEQ has reliable, time-tested mechanisms for reporting environmental emergencies and for providing notice when pollution control equipment fails. These work well on a day-to-day basis. However, Arkansas's February experience as well as lessons learned from disasters in Louisiana, Texas, and other states suggests that such systems are not designed for or intended to address multiple, simultaneous emergencies. DEQ could be given the authority, when authorized by the Governor and consistent with federal law, to expand reporting mechanisms temporarily to include resources such as Twitter, Facebook, or other electronic means of communication that DEQ determines, to enable those who are perhaps without power and/or are stranded to provide legally valid notice to the agency of emergency situations.
- Regarding pollution control equipment, it is important not to try to "fight the last war." The next major emergency might just as easily be a long-predicted New Madrid fault earthquake or regional power outage of extended duration as opposed to a sustained deep freeze. Although reporting requirements under federal law such as the Emergency Planning and Community Right-to-Know Act ("EPCRA"), 42 U.S.C. § 11001 *et seq.*, already exist, it might be helpful for DEQ to review whether its existing documentation is organized in a manner such that DEQ can quickly identify which pollution control equipment it regulates in a region of the state, if any, might pose an immediate threat to human health in the event of a catastrophic failure.

- DEQ and APSC should consider what advance authority they would need the Governor to have to enable either agency, as appropriate, to intervene, perhaps by invitation and perhaps not, when a critical resource, e.g., natural gas, needs to be rationed and there is a dispute among private entities regarding how best to do so in a manner that best serves the public. Indeed, a distributor might prefer to have state assistance in making such determinations to relieve the distributor of competing, irreconcilable contractual obligations.
- The Task Force may want to give separate consideration to whether an electronic system could be used to remind relevant parties of the ability the State has to assist with any new authorities that might arise from the Task Force's work. A sophisticated company addressing a myriad of problems at once, as always occurs during an emergency, is unlikely to be familiar with the different authorities possessed by each state in which the company operates and might not have immediate access to someone who is.
- The Task Force's recommendations that are adopted could be implemented as rules to the extent statutory authority already exists for the proposed action. Where new statutory authority is required, draft rules could be prepared by the Task Force in advance, to ensure that the statutory authority provided is adequate to implement the Task Force's objectives. Of course, such draft rules would then have to be properly noticed and subject to comment once the necessary statutory authority was provided.
- The Task Force should consider whether the State could provide additional funding to key agencies to enable them to offer voluntary stress testing to facilities. This could include environmental and energy-related issues as well as logistical and transportation infrastructure concerns. Many companies' personnel have experience working in a particular geographic region, and their emergency experience is based on the types of emergencies they and their colleagues typically experience. The State should consider whether it could help interested facilities identify in advance low-probability/high-impact events that are outside the experience of most day-to-day operators and that might have unpredictable consequences for a particular facility. It is essential that such a program be voluntary to ensure it receives adequate support.

Governor Hutchinson has presented the Task Force with a critical job, and I appreciate the Task Force diligent efforts in carrying it out. I hope that these comments are of some use to the Task Force. Of course, I would be pleased to elaborate on any of this if it would be of any assistance to the Task Force.

Sincerely,

QUATTLEBAUM, GROOMS & TULL PLLC

Michael B. Heister

MBH:lsw

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE

**RESPONSE OF BLACK HILLS ENERGY ARKANSAS, INC.
TO QUESTIONS FROM THE TASK FORCE**

On April 13, 2021, Black Hills Energy Arkansas, Inc. ("BHEA") received questions from the Task Force and respectfully submits the following responses.

Q1a. IT APPEARED FROM THE ENERGY COMMITTEE TESTIMONY THAT THE SHORTAGE OF NATURAL GAS COMING INTO ARKANSAS CONTRIBUTED SIGNIFICANTLY TO THE POWER SHORTAGE IN THE STATE DURING THE FEBRUARY WINTER EVENT. COULD YOU ELABORATE ON THE REASONS FOR THAT SHORTAGE AND WHAT IMPACTED THE NATURAL GAS SUPPLY?

A. BHEA contracts with gas marketers for gas supply and with interstate pipeline companies to have that supply transported and delivered to its local distribution systems in Arkansas. During the February winter event, BHEA received force majeure notices from multiple gas suppliers stating that they would be unable to deliver contracted volumes due to freezing of natural gas wells and related facilities. BHEA also received notices from multiple interstate pipeline companies requiring it reduce volumes taken from the pipelines due to "the unprecedented level of natural gas production freeze-offs and other supply disruptions," and "severe cold weather conditions and receipt supply shortfalls." The pipeline notices also mentioned insufficient supply delivered from upstream interconnect locations, upstream suppliers that are unable to meet their scheduled deliveries, and failure of compressor facilities.

The Energy Information Administration ("EIA") reported that U.S. dry natural gas production fell to as low as 69.7 billion cubic feet per day (Bcf/d) on February 17, a decline of 21%, or down nearly 18.9 Bcf/d from the week ending February 13. Also according to EIA, natural gas production in Texas fell almost 45% from 21.3 Bcf/d during the week ending February 13 to a daily low of 11.8 Bcf/d on Wednesday, February 17. EIA further reported that the decline in natural gas production was mostly a result of freeze-offs, which occur when water and other liquids in the raw natural gas stream freeze at the wellhead or in natural gas gathering lines near production facilities. At the same time natural gas demand for both direct end use across BHEA's system and power generation across much of the nation was very high. Demand for natural gas on BHEA's system went to record highs as BHEA exceeded its previous peak day demand by more than 10%.

Q1b. NATURAL GAS BEING USED BOTH FOR HOME HEATING AND POWER GENERATION CONTRIBUTED TO THE INCREASED DEMAND. ARE THERE MITIGATION STRATEGIES WHICH COULD BE EMPLOYED TO ENSURE ARKANSAS HAS ADEQUATE SUPPLIES OF NATURAL GAS DURING FUTURE WEATHER EVENTS? ARE THERE EVENTS OR SCENARIOS, OTHER THAN WEATHER EVENTS, WHICH COULD IMPACT THE SUPPLY OF NATURAL GAS IN ARKANSAS?

A. Presumably, supply would have more closely met demand if freeze offs of natural gas wells and related facilities had not occurred. Therefore, more effective winterization of those facilities would be a logical step. However, since the freeze off related supply disruptions seemed to occur mostly in other states, it may be difficult for Arkansas to directly address that situation.

On the natural gas supply side, continued supportive policy and a regulatory environment that encourages natural gas production, storage and pipeline development is important to ensure adequate supply of natural gas during future weather events. For example, the APSC's approval of BHEA's acquisition of additional storage facilities in 2015 provided BHEA with storage facilities that were critical to meeting supply deliverability during the weather event.

On the natural gas demand side, energy efficiency and weatherization programs can continue to play an important role, including programs that optimize the efficiency of natural gas usage at both the power plant and the consumer burner tip including technologies such as high efficiency natural gas heat pumps, furnaces, tankless water heaters, and smart thermostats.

There are events or scenarios, other than weather events, which could impact the supply of natural gas in Arkansas. These include natural disasters such as earthquakes that cause pipeline ruptures, pipeline damage caused by insufficient excavation practices, and acts of terrorism. Energy policies that increase the cost of exploring for, producing, and delivering natural gas or restrict activities related to exploring for, producing and delivering natural gas such as leasing, drilling, fracking, etc. could also impact the supply of natural gas in Arkansas over the longer term.

Q1c. GIVEN THAT THE SUPPLY OF NATURAL GAS WAS SIGNIFICANTLY AFFECTED DURING THE FEBRUARY WINTER EVENT AND RESULTED IN CURTAILED SUPPLY TO CUSTOMERS, WHAT ARE THE PROTOCOLS TO

DETERMINE WHICH CUSTOMERS WILL BE AFFECTED FOR THE REMAINDER OF THE YEAR?

A. In Arkansas natural gas customers may be curtailed by either the natural gas utility delivering gas to the customer or by the interstate pipeline delivering the customer's gas to the natural gas utility or directly to the customer. Both situations occurred during the February winter event. When it becomes necessary for BHEA to curtail its customers BHEA determines the customers to be curtailed in accordance with its curtailment policy. BHEA's curtailment policy is included in its tariffs filed with and approved by the Arkansas Public Service Commission ("APSC") as Policy Schedule 4.1. A copy of BHEA's curtailment policy is attached. Curtailments may be caused by pipeline capacity constraints on BHEA's pipeline system or by gas supply or upstream pipeline capacity constraints. The curtailment procedure is different depending on the cause of the curtailment but in either scenario, human needs customers are exempt from curtailment. BHEA's curtailment policy defines human needs as: "hospitals, housing, greenhouses, poultry farms, public and private schools (except colleges and/or universities having central boiler plants for heating and an alternative fuel source)."

Curtailments may be limited to specific areas rather than system wide depending on where the gas supply or capacity constraint occurs. For example, if BHEA has a gas supply or capacity constraint in the Bentonville area, it would probably not help to curtail customers in the Clarksville area. The curtailment policy establishes an order of curtailment based on the customer's gas consumption with customers having greater consumption being curtailed first. When BHEA curtails a customer the curtailment policy provides that BHEA will, to the extent possible, allow a minimum volume of gas consumption for heating necessary to avoid physical damage to the customer's facility.

BHEA provides only transportation service for some large business customers. These transportation customers buy their own gas supply from gas marketers or producers and have it delivered to BHEA's pipeline system through interstate pipelines. They pay a transportation rate to BHEA to have the gas delivered to their business locations. When there are gas supply or capacity constraints on the interstate pipeline systems delivering gas to BHEA, these customers may be curtailed by the interstate pipeline. This actually happened on the morning of February 16 when one interstate pipeline delivering gas to BHEA's system on behalf of multiple BHEA large business customers issued an Emergency Response Operational Flow Order requiring all customers who had not submitted a human needs affidavit to reduce their deliveries from the pipeline to zero within two hours. This order affected multiple BHEA transportation customers.

Q1d. WHAT ADDITIONAL STRATEGIES, REGULATIONS, PROTOCOLS, INCENTIVES AND/OR POLICES SHOULD BE DEVELOPED BY INDUSTRY OR GOVERNMENT TO ENSURE ARKANSAS HAS AN ADEQUATE NATURAL GAS SUPPLY?

A. At the same time that Arkansas desires affordable, abundant natural gas supplies with high reliability, the federal government and some state and local governments are adopting policies that could restrict the supply of natural gas and increase the cost of producing natural gas and building natural gas infrastructure. The government of Arkansas should work with its congressional delegation and also through the court system when appropriate to encourage balanced federal energy policy that fully develops all of America's energy fuel sources, technologies, and energy infrastructure in an economical, sustainable, and reliable manner.

It is also important for Arkansas to continue to ensure supportive policy and a regulatory environment that encourages natural gas production, storage, and pipeline development. BHEA will continue to assess and evaluate prudent natural gas utility investments that support increased supply reliability and will work with the APSC in addressing timely cost recovery of such investments. Additionally, providing support for potential investment in renewable natural gas and hydrogen projects can also have an important role in ensuring Arkansas has an adequate natural gas supply.

Additionally, when electric utilities implement rolling blackouts during cold weather events, there should be coordination with gas utilities to the extent possible. Blackouts initially provide some relief to the natural gas system as gas appliances that require electricity go offline. However, when the blackout ends there is a sudden surge in natural gas demand as 100% of those appliances come back on at the same time. Sudden surges in gas demand during already peak conditions can cause pressure drops on the gas utility system that may result in loss of service to segments of the system.

Q2. WHAT INCENTIVES COULD THE STATE PROVIDE TO HELP ENSURE AN ADEQUATE SUPPLY OF NATURAL GAS DURING EXTREME WEATHER EVENTS?

A. See response to Q1d above.

Q3. WHAT WOULD BE YOUR RECOMMENDATIONS TO ENSURE AN ADEQUATE SUPPLY OF NATURAL GAS FOR THE STATE DURING EXTREME WEATHER EVENTS OR OTHER TYPES OF SUPPLY DISRUPTIONS?

A. See responses to Q1d above.

Q4. DESCRIBE YOUR PREPAREDNESS AND ALLOCATION PROCESS FOR CRITICAL ENERGY RESOURCES DURING EXTREME EVENTS.

A. Weather related curtailments on BHEA's system are very rare. Prior to the February winter event, BHEA's last weather-related curtailment occurred approximately 25 years ago. BHEA designs its pipeline system and gas supply portfolio around a Design Peak Day which represents the coldest weather conditions on its system within the last several decades. Using multiple forecasting models, the pipeline system, underground storage and gas supply portfolio is designed to provide adequate gas supply and capacity under conditions replicating the design peak day at the peak hour of that day. Pursuant to the APSC Natural Gas Procurement Plan Rules ("Rules"), BHEA annually files a Gas Supply and Capacity Plan with the APSC which is reviewed by the APSC Staff. Pursuant to the Rules, BHEA's plan is designed around the principal that it should produce a diversified gas supply portfolio designed to yield an appropriate balance of reliability, reduced volatility, and reasonable price.

When extreme winter weather is forecasted, BHEA strives to operate its pipeline system near maximum allowable pressures in preparation for stronger demand. BHEA also continuously monitors its gas supply and key infrastructure while also encouraging customers to conserve energy. If the forecast is for very severe conditions BHEA may also advise large customers of the potential for curtailments and ask for voluntary volume reductions.

When a curtailment event actually occurs, customers are curtailed in accordance with BHEA's curtailment policy. See response to Q1c above. During a curtailment event the objective will be to reduce demand to the extent required to maintain service to residential and other human needs customers.

Q5. DESCRIBE YOUR NOTIFICATION PROCESS TO END USERS WHEN CURTAILING SERVICES. HOW DOES THE END USER APPEAL OR REQUEST CONSIDERATION OF UNIQUE CIRCUMSTANCES UPON NOTIFICATION?

A. When curtailment of a BHEA customer is necessary, a representative of BHEA will call the customer to notify them of the curtailment. If a customer wants to request consideration of unique circumstances, the customer would make such a request at that time. However, when a curtailment situation arises there is little room for flexibility due to the urgency of maintaining service to residential and other human needs customers. When a curtailment seems imminent but potentially avoidable, BHEA will call curtailable customers in the affected area and ask for voluntary volume reductions.

Original Sheet No. 1 of 3 Replacing Black Hills Energy Arkansas, Inc. d/b/a/ Black Hills Energy (Name of Company) Kind of Service: Natural Gas Class of Service: All Policy Schedule No.: 4.1 Title: Curtailment Policy – (PS-1)	PSC File Mark Only

CURTAILMENT POLICY-(PS-1)

Whenever the supply of natural gas, upstream pipeline capacity or the capacity of the Company's transmission or distribution system in any area is less than the amount required to meet the needs of all customers in that area, the Company shall have the right to curtail the use of natural gas by its customers in the area where the shortage exists. The Company shall not be liable for any loss or damage that may be sustained by any customer by reason of curtailment. If continuity of energy supply is required by any customer, the customer should install and maintain whatever back-up energy system that may be needed.

The order for curtailment of customers shall be based upon the annual consumption during current or preceding year. If there is not sufficient consumption history to establish the annual consumption for prioritizing curtailment, the Company, in its sole discretion reasonably exercised, will estimate the annual consumption. Those customers having the highest annual consumption in the area where the shortage exists shall be subject to curtailment first. To further define curtailment, the following shall be the applicable order of curtailment:

Curtailment Due To Gas Supply and Upstream Pipeline Capacity:
If the reason for the curtailment is due to a shortage of gas supply and/or upstream pipeline capacity, curtailments shall be made as follows:

System Supply Customers:

1. Class 1 – Curtailment: Non-exempt system supply customers (see Exemption below) whose annual consumption is in excess of 300,000 Ccf shall be first to curtail.

2. Class 2 – Curtailment: Non-exempt system supply customers (see Exemption below) whose annual consumption is in excess of 50,000 Ccf but less than 300,001 Ccf shall be curtailed after Class 1 curtailments.

3. Class 3 – Curtailment: All other non-exempt system supply customers (see Exemption below).

4. Class 4 – Curtailment: All remaining system supply customers.

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Transportation Customers:

Transportation customers whose supply of natural gas is delivered to the Company's transmission or distribution system shall not be subject to curtailment due to a shortage of gas supply and/or upstream pipeline capacity.

Curtailment Due to Company Transmission and/or Distribution Capacity Constraints:
If the reason for the need to curtail is due to capacity constraints on the Company's own transmission or distribution system, curtailment shall be made in the following order:

1. Class 1 – Curtailment: Non-exempt system supply and transportation customers (see Exemption below) whose annual consumption is in excess of 300,000 Ccf shall be first to curtail.

2. Class 2 – Curtailment: Non-exempt system supply customers and transportation customers (see Exemption below) whose annual consumption is in excess of 50,000 Ccf but less than 300,001 Ccf shall be curtailed after Class 1 curtailments.

3. Class 3 – Curtailment: All other non-exempt system supply and transportation customers.

4. Class 4 – Curtailment: All remaining system supply and transportation customers.

Exemption:
Human needs customers shall be exempt from curtailment. Human needs include hospitals, housing, greenhouses, poultry farms, public and private schools (except colleges and/or universities having central boiler plants for heating and an alternative fuel source). However human needs customers in the Class 1 and Class 2 curtailment category that have a back-up energy system installed that can replace natural gas as the energy source for all of the facility's human needs requirements and provide the Company an affidavit stating such and releasing the Company from any liability shall have the right to request that it not be considered as an exempt customer and therefore be subject to curtailment.

Original Sheet No. 3 of 3 Replacing Black Hills Energy Arkansas, Inc. d/b/a/ Black Hills Energy (Name of Company) Kind of Service: Natural Gas Class of Service: All Policy Schedule No.: 4.1 Title: Curtailment Policy – (PS-1)	PSC File Mark Only

Penalty for Non-Interruption:

To the extent possible, the Company shall allow a minimum of consumption during periods of curtailment, for such heating necessary to avoid physical damage. All other gas usage must be discontinued during specified periods of curtailment.

If a customer fails to curtail his use of natural gas hereunder when required to do so by the Company, gas service may be discontinued and/or the customer will be charged for all gas consumed during such period of curtailment at a rate of $10.00 per Mcf. Failure to curtail is when gas usage during the period of curtailment exceeds minimum heating requirements as described herein.

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ENERGY RESOURCES PLANNING TASK FORCE

TESTIMONY QUESTIONS

Please send your responses to ERPTaskForce@arkansas.gov on or before April 30, 2021.

NATURAL GAS PRODUCERS AND SUPPLIERS

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

- It appeared from the Energy Committee testimony that the shortage of natural gas coming into Arkansas contributed significantly to the power shortage in the State during the February winter event. Could you elaborate on the reasons for that shortage and what impacted the natural gas supply?

Response of CenterPoint Arkansas: CenterPoint Arkansas is a natural gas distribution company that serves natural gas to its end-use customers. CenterPoint Arkansas does not serve any power generators; therefore, it has no direct knowledge of what caused the electric power shortages in the state. CenterPoint was able to obtain all the necessary supply required to fully supply its obligation to its sales customers and did not experience any inability to meet its supply obligation.

Delivering natural gas to customers has two components—commodity gas supply and transportation. CenterPoint Arkansas has two general types of customers--sales customers and transportation customers. To serve sales customers, CenterPoint Arkansas purchases gas, arranges interstate pipeline transportation and delivery of the gas into its distribution system, and distributes that gas through its system to its customers' homes and businesses. Transportation customers are generally large commercial customers that work with third party suppliers to purchase gas and deliver it through the interstate pipelines to CenterPoint Arkansas's distribution system for final delivery to the customer. Both the Company and transportation customers are themselves customers of interstate pipelines, as transportation customers independently contract for this service, instead of using CenterPoint Arkansas's all-in-one sales services.

Although prices were extraordinarily high during the February winter event, CenterPoint Arkansas was able to obtain all the necessary gas supply required in order to fully supply its obligations to its sales customers and to transport it into its distribution system for delivery to the end-use customers. Enable Gas Transmission is an interstate pipeline system that is CenterPoint's primary source for deliveries of gas into its distribution system. Given limits on its system during the February winter event, Enable announced that it would only deliver gas on behalf of customers who supplied human needs, and only up to their stated human needs. With that announcement, transportation customers' gas supplies that were not for human needs ceased to be delivered into the Company's distribution system. After this occurred, the Company was only able to receive gas purchased for its sales customers and the human needs of transportation customers. Any further gas consumed by non-human needs transportation customers would have reduced the amount of gas available to sales customers. At that point, the Company invoked its curtailment tariff[1] on file with and approved by the Arkansas Public Service Commission for its non-human needs transportation customers, and ceased to allow these customers to use any more gas from its distribution system.

- Natural gas being used both for home heating and power generation contributed to the increased demand. Are there mitigation strategies which could be employed to ensure Arkansas has adequate supplies of natural gas during future weather events? Are there events or scenarios, other than weather events, which could impact the supply of natural gas in Arkansas?

Response of CenterPoint Arkansas: As a natural gas distribution company that does not supply any power generators, CenterPoint Arkansas has no direct knowledge of what caused the electric power shortages in the state. Although prices were high, the Company was able to obtain all the necessary gas supply required to fully supply its obligations to its sales customers and did not experience any inability to meet its supply obligations.

The Company was able to maintain deliveries into its distribution systems because it pays interstate pipelines for "firm" service, which means its gas shipments have the highest possible priority. Firm transportation is one way to ensure that supplies are available during periods of high capacity utilization. There are a number of other events or scenarios that could impact the supply of natural gas in Arkansas, including damage to underground facilities or other operational issues.

- Given that the supply of natural gas was significantly affected during the February winter event and resulted in curtailed supply to customers, what are the protocols to determine which customers will be affected for the remainder of the year?

Response of CenterPoint Arkansas: Curtailment is conducted pursuant to the Company's tariff on file with and approved by the Arkansas Public Service Commission.

- What additional strategies, regulations, protocols, incentives and/or polices should be developed by industry or government to ensure that Arkansas has an adequate natural gas supply?

Response of CenterPoint Arkansas: As mentioned above, CenterPoint was able to obtain all the necessary gas supply required to fully supply its obligations to its sales customers and did not experience any supply failures. Nevertheless, there were market areas across America that did not see as much impact as the mid-continent states. Diversity of supply locations is critical during times like February and will create more reliability and supply options. Additional local supplies or local storage capability would reduce Arkansas's dependence on out-of-state supply and would reduce Arkansas's need for interstate transportation of gas. Working with existing pipelines to improve existing or develop new interconnects to other pipelines and exposing Arkansas to

[1] https://www.centerpointenergy.com/en-us/Corp/Documents/Arkansas%20Rates%20and%20Tariffs/OrderofCurtailment.pdf. CenterPoint's curtailment tariff allows it to "take steps necessary for the protection of the reliable and adequate service." Under the policy, "deliveries of gas will be curtailed to whatever extent and or whatever periods Company may find it necessary from time to time in the operation of its system for the primary benefit of human needs customers."

additional supply basins would add incremental reliability. All these options come at a higher cost to the Company, its customers and to upstream service providers.

2. What incentives could the state provide to help ensure an adequate supply of natural gas during extreme weather events?

Response of CenterPoint Arkansas: As a regulated public utility, certainty of recovery of costs necessary for additional supply or transportation options would incentivize additional reliability projects.

3. What would be your recommendations to ensure an adequate supply of natural gas for the state during extreme weather events or other types of supply disruptions?

Response of CenterPoint Arkansas: As mentioned above, CenterPoint was able to obtain all the necessary gas supply required to fully supply its obligations to its sales customers and did not experience any supply failures. Developing local supplies or storage capabilities, working with existing pipelines to improve existing or develop new interconnects to other pipelines and exposing Arkansas to additional supply basins may add incremental reliability.

4. Describe your preparedness and allocation process for critical energy resources during extreme events.

Response of CenterPoint Arkansas: With the support of the Arkansas Public Service Commission, CenterPoint has invested in modernizing its system to ensure that its facilities can reliably serve customers during extreme weather events. CenterPoint's system is designed to serve needs required during a coldest day scenario (i.e. the coldest day in thirty years), supported by corresponding upstream supply services.

5. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Response of CenterPoint Arkansas: CenterPoint notifies curtailed customers pursuant to its curtailment tariff on file with and approved by the APSC. Affected customers are notified via electronic communication such as email or via phone communication. Curtailed customers may request consideration of unique circumstances pursuant to Section 9.8 of the Company's curtailment tariff.

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ENERGY RESOURCES PLANNING TASK FORCE INQUIRY RESPONSE

Sent via email on April 30 to: ERPTaskForce@adeq.state.ar.us

BACKGROUND:

AECC is a generation and transmission electric cooperative owned by our 17 Member Cooperatives, who serve approximately 1.3 million Arkansans in 74 of Arkansas's 75 counties. More information about AECC is online here: https://aecc.com/about-us/. Because AECC is a non-profit utility, organized as an I.R.C, § 501(c)(12) cooperative, we support any efforts that would result in lowering the overall cost of electric service to Arkansas' end-use consumers. In that vein, AECC appreciates the Task Force's efforts to investigate the circumstances around the February 2021 extreme weather event, particularly given our membership bore both the financial and operational brunt of circumstances outside of our control.

Should you need additional information supporting these responses, please contact Jennifer Loiacano, AECC's NERC Compliance Supervising Attorney, at 501.570.2187, Jennifer.Loiacano@aecc.com, or AECC's General Counsel, Lori L. Burrows, at 501.570.2147 or Lori.Burrows@aecc.com, and they will assist in getting relevant and timely information to the Task Force.

ELECTRIC UTILITIES

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

    - In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?

      RESPONSE: The primary causes of the electric power shortage were the unprecedented and extraordinary nature of the weather event, which was widespread across the continental US and longer in duration than any weather event in recent history. The widespread nature of the event, coupled with record low temperatures, created an all-time high demand for energy from electric utilities, a constraint in fuel supply and a lack of dispatchable resources.

      Mitigation strategies are identified in the responses to Question Nos. 4, 7 and 8.

- Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?

  RESPONSE: AECC has ongoing, internal reviews to identify the root causes and appropriate additional strategies to mitigate the results of such matters in the future. To support grid stability, AECC has historically relied on a mix of generation, as a means to avoid over reliance on one type of generation.

  Other extraordinary events that could significantly affect power availability include earthquakes, widespread flooding, and terrorist events.

- What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

  RESPONSE: AECC's evaluation of potential preventive, future measures is underway. AECC's evaluation will include a cost-benefit analysis for system and end-use consumers' needs.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

   RESPONSE: AECC, as well as other utilities throughout the state, is currently, and continually, reviewing and adjusting its generation mix to ensure the proper allocation and availability of resources, as mentioned above.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

   RESPONSE: Currently many utilities manage capacity based on the requirements of the Regional Transmission Organization (RTO, i.e., SPP and MISO for Arkansas) they are in. The RTOs assign capacity values to renewable resources that are added to the generation mix. Currently the SPP and MISO interconnection queues are almost entirely full of new wind and solar resources that get capacity credit. In other words, it appears reliance on wind and solar for capacity will increase, perhaps significantly. The RTOs should be held accountable to ensure that increased reliance on these resources for capacity does not increase the number and magnitude of energy emergencies such as occurred with the extreme weather event in February. Also, the RTOs should be held accountable to a reasonable and reliable dispatchable reserve margin. Since all utilities rely on the market, it is essential that this step be right. Actions to ensure reliability by a single utility will have minimal value; actions must be required and adopted RTO-wide.

4. Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

   RESPONSE: The onsite fuel storage processes AECC has implemented, as well as local fuel availability, provided the most significant backup through the recent cold weather event. These onsite storage processes provided enough coal to span the duration of the severe weather event, even with the freezing issues that decreased generation output levels. Also, AECC was able to replenish diesel fuel used at one of its dual fuel plants where natural gas was unavailable during that period. AECC will continue to evaluate cost-effective ways to further expand on-site storage of fuels to both reduce costs and help make the overall electric system even more resilient. On-site fuel storage could be key to the reliable contribution of future power plants in Arkansas.

   With respect to emerging technologies, currently available electric battery storage systems have relatively short useful lives and the associated costs are too high for broad economic application to electric grid supply. However, battery system costs are gradually decreasing and technologies are being developed that are expected to achieve longer useful operating lives. Electric battery storage as well as advances in pumped storage hydroelectric plants will continue to be evaluated for overall benefits, including how those could assist in mitigating episodic and severe weather events. These short-term storage devices can also provide effective ancillary services to the wholesale energy markets (e.g., fast ramping up and down) although the volume of need for those services is relatively small in comparison to the overall volume of the markets.

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?

   RESPONSE: See the response to Question 4 above. Battery and pumped storage hydroelectric systems provide short term storage cycles (typically 2-4 hours for batteries and 6-12 hours for hydro). These systems would be of little value for the most extreme weather events, given they are not currently well-suited to supplying power on a continuous basis for multiple days, such as the grid experienced in mid-February 2021.

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

   RESPONSE: All sources of load reduction are beneficial when the demand is outstripping supply, but it is unclear the degree to which EE programs contributed to load management during the severe weather event.

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

   RESPONSE: AECC's wholly owned facilities did well during the February 2021 severe weather event with only minor weather-related issues beyond the ability to obtain fuel. To prepare for the event, all AECC wholly owned and operated plants performed cold weather checklists applicable to their respective facilities in anticipation of cold weather prior to the winter season and immediately prior to the February cold weather event. Generation facilities also increased monitoring, focusing on the anticipated effects of the severe weather and to provide staff adequate time to address issues pro-actively. All fossil fuel plants that operated during the severe weather augmented resources with additional operations and maintenance staff. Supervision was on site most of the event and available by phone, if needed. Plant management provided daily updates, and generation facility needs were prioritized to ensure generation was maintained.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

   RESPONSE: AECC and the 17 Member Cooperatives maintain an Emergency Load Conservation and Curtailment Plan (ELCCP)[1] that establishes a process for curtailing load, when needed, such as during the recent severe weather event as required by NERC, SPP, and approved by the Arkansas Public Service Commission (APSC). AECC, as included in the approved APSC tariff, will notify the APSC and other appropriate governmental agencies and file any necessary follow-up reports to meet APSC and/or other governmental agency requirements following a curtailment event.

   Each Member Cooperative has its own process for notifying its end-use, retail consumers in the event of curtailment, including notification by phone, media outlets (local news stations, radio stations, newspapers), social media, and other public outlets.

[1] *See* Arkansas Electric Cooperative Corporation Tariff on file with the APSC, Schedule Emergency Load Conservation and Curtailment Policy, available at http://www.apscservices.info/tariffs/2_elec_1.PDF.

ARKANSAS MUNICIPAL POWER ASSOCIATION

April 30, 2021

Arkansas Municipal Power Association's

Responses to Questions Presented by the Arkansas Energy Resources Planning Task Force

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I. Introduction

The Arkansas Municipal Power Association (AMPA) appreciates the opportunity to provide our responses to the questions presented by the Energy Resources Planning Task Force. AMPA is composed of the 15 municipal electric utilities (MEUs) that serve over 425,000 Arkansans. These MEUs are diverse. Five of the ten largest cities in Arkansas are served by MEUs. Conversely, the five smallest MEUs serve a combined population under 20,000. They are divided between the footprints of SPP and MISO, with one, the City of Prescott, having the unique and unfortunate distinction of being included in both. MEUs generate and/or purchase electric power for customers from a variety of sources, including:

- Shared or sole ownership of electric generating units;
- Contracts for the full or partial output of electric generating units;
- Contracts for fixed amounts of energy and/or capacity;
- Contracts for variable amounts of energy and/or capacity based on load;
- Allocations from the Southwestern Federal Power System; and
- Direct purchases of energy and capacity through markets managed by MISO and SPP.

The power resources described above include a diverse mix of fossil fuel and renewable generation resources. Seven MEUs have direct financial interests in coal-fired electric generating units located in Arkansas. Four MEUs have local gas or petroleum-fired electric generating units. Ten MEUs have renewable generation resources, including: (1) 239.5 MW of hydropower that is owned or purchased through contracts; and (2) 170 MW of solar power that is owned, purchased through contracts, or under contract for development. Additional solar development is being planned. Contracts and market purchases are typically silent regarding the source of energy and/or capacity purchased and may include a variety of resources.

II. Responses to Questions

1. ***Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas*:**

- ***In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event?***

Response**:** During the February winter event, some AMPA members experienced curtailments due to electric power shortages, but others did not. Curtailments, when they occurred, were limited in duration. Thus, from AMPA's perspective, the February winter event did not result in an electric power shortage as much as it resulted in the replacement of low-cost generation with high-cost generation while demand peaked. This created severe upward pressure on market prices and in turn pushed higher costs onto load serving entities, like MEUs.

AMPA attributes the alarming prices experienced during the February winter event to: (1) increased demand for electricity; (2) reduced output from generating units that typically produce electricity at favorable prices; and (3) increased cost of natural gas. In MEUs, homes and businesses rely on electricity for heat. It is often their sole source. The extreme cold temperatures caused these customers to consume electricity at near-record levels. While the demand for electricity was peaking, many low-cost generators struggled. Some plant components were either frozen or too cold to operate. There were reports of frozen coal piles and frozen natural gas wellheads. Pricing in the natural gas market – which had been relatively stable at $3/mmbtu – soared to over $1,000/mmbtu. Further, renewables did not seem prepared to fill the gap. The SPP market, for example, seemed significantly impacted by a loss of wind energy that normally provides an abundance of affordable power. Overall, AMPA believes that extreme cold temperatures caused a simultaneous increase in demand for electricity, decrease in affordable generation, and spike in natural gas pricing which resulted in record market prices for electricity.

- ***What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?***

Response**:** AMPA members reported that voluntary curtailment was the primary mitigation strategy to manage price exposure during the February winter event. Additional mitigation strategies used by AMPA members vary based on the methods they use to purchase or generate electricity.

a. Single provider. Some AMPA members depend on a single wholesale power provider for all of their energy, capacity, and ancillary service needs. These MEUs typically have contract terms that restrict their ability to enter contracts with other providers or construct generation that would mitigate exposure during peak events. They are fully dependent on the diligence of their wholesale power provider. In general, most MEUs in this situation fared well. However, the MEUs that rely on SWEPCO as their wholesale provider received bills that were five times greater than average. The City of Bentonville, expecting a monthly bill of approximately $4M, was billed over $20M for the month of February. Similarly, Hope Water & Light and the City of Prescott saw costs increase by approximately $5.2M and $2.0M, respectively. The combined losses of the three AMPA members served by SWEPCO exceed the combined losses of the other twelve AMPA members.

b. Contract purchasers. Some AMPA members depend on layered energy contracts ("block purchases") to mitigate exposure to market swings. These contracts reduce market exposure in accordance with the risk management policy of the utility and often rely on weather forecasting. The NOAA's weather forecast contributed to greater volatility for contract purchasers because, as late as January 27th, it predicted an unseasonably warm February. Thus, load was projected at lower levels. The resulting gap between forecasted load and actual load caused some AMPA members to purchase more wholesale power in the Day-Ahead and Real-Time markets than was projected, while those markets were peaking.

c. Local Generation. Some AMPA members use their own electric generation assets to mitigate exposure to market swings. MEUs that own generators reported that they used checklist procedures to verify preparation for cold weather operations. However, additional procedures were required for the February winter event. Maintenance teams worked around the clock to keep units warm enough to start. Portable heaters and tarps were used to protect external components.

For owners of natural gas generators, fuel supply was particularly challenging. Paragould Light, Water and Cable (PLWC) relies on 32 MW of local natural gas generation to mitigate peak events. These generators were ready and available to run but had no fuel. Conversely, Jonesboro City Water and Light (CWL) was able to coordinate natural gas delivery through Tenaska. The financial impact of the February winter event on these two municipal utilities demonstrates the importance of natural gas supply. CWL incurred no significant financial impact during the event while PLWC had increased costs of $8,500,000.

- ***Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future?***

Response**:** AMPA believes that additional strategies could be employed to improve the reliability of electric power in Arkansas.

a. Improve the ability of natural gas production to ramp-up during peak events.

b. Improve market-to-market coordination between SPP and MISO. The distribution systems of CWL and PLWC are approximately 15 miles apart, but CWL is in MISO's footprint and PLWC is in SPP's footprint. At one point during the event, CWL attempted to support PLWC by moving power across a transmission line between the two cities that is owned by the federal Southwest Power Administration. The line appeared to have capacity to support the transfer. However, when CWL and PLWC followed the necessary processes to "tag" the transmission between the systems, neither MISO nor SPP would approve it. AMPA submits that if one ISO served the state of Arkansas instead of two, the event described above would not have happened. If Arkansas is to be served by two ISOs, these ISOs need to coordinate their efforts to best serve the needs of the state.

- ***Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?***

Response: Regional transmission organizations like MISO and SPP have sophisticated models to balance electric demand with generator availability. However, despite their efforts, there are scenarios or a combination thereof that could result in inadequate power. First, unexpected transmission outages could occur resulting in constrained generation. Second, unexpected generation outages could occur resulting in lowered supply that is inadequate to meet demand. Third, forecasting errors could result in demand that is higher than available generation. Fourth, generators could underperform resulting in insufficient generation to meet demand. Fifth, generators or transmission lines could be disabled by terrorist or cyber-attack. Finally, the retirement of EGU's without sufficient replacement of dispatchable generation capacity could result in inadequate generation to meet demand.

- ***What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?***

Response: Arkansans currently benefit from an abundance of electric generation capacity. To preserve this benefit, the pace of new capacity installations must meet or exceed both: (1) planned retirements; and (2) reasonably foreseeable increases in load, particularly increases in load that will result from electrification of the transportation sector. Consideration should also be given to the importance of a diverse fuel mix. Dispatchable base load units, like those powered by fossil fuels, will be critical to maintaining a reliable electric grid.

As new generation is developed, transmission systems must be modified to facilitate the delivery of energy. AMPA believes that transmission systems need to be able to adapt to the changing generation landscape without creating an undue burden on consumers.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response: AMPA believes that the owners of electric generating units as well as owners of fuel supply infrastructure should evaluate additional measures to better winterize their assets in light of the February winter event. In this regard, AMPA does not ignore the importance of cost/benefit analysis. Coal units in Arkansas are designed to operate in a summer peaking region. AMPA would not seek to improve winterization for coal units that would decrease the summertime efficiency.

Additionally, better coordination between fuel and electric markets is needed to ensure that appropriate amounts of fuel will be available when needed.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response:

a. Reasonable and predictable environmental standards. AMPA believes that the current electric generation capacity mix is threatened by national environmental policy. AMPA members that have invested in coal-fired plants are anticipating early retirements and, in some cases, stranded costs. Given that experience, AMPA members will be hesitant to invest in any fossil fuel resource that appears to be threatened by environmental regulation. Unfortunately, AMPA is unaware of any economically viable solution to provide peak power during extreme weather events over the next decade that is not based on fossil fuel.

b. Reliable supply of natural gas. Generators fueled by natural gas tend to be the most responsive during emergencies. However, as shown in the February winter event, natural gas generation is only as helpful as the availability of fuel. Thus, a reliable supply of natural gas is key to serve peak load during extreme weather events.

4. Are there reasonably available storage solutions for electricity that could be implemented in the state?

Response: AMPA believes that pumped-storage hydropower and new battery technology are both available for implementation in Arkansas, but both have drawbacks, particularly related to cost.

a. Pumped storage. Arkansas has substantial water resources. Pumped-storage hydropower is a proven method to store energy at utility scale. Pumped storage is challenged by high-capital costs and environmental issues, particularly those related to the killing of fish.

b. Batteries. Battery technology is rapidly improving and costs continue to decline. Unfortunately, batteries do not appear to be an economically viable option for large scale energy storage at today's prices.

- ***What are the barriers or impediments to deployment of storage technologies?***

Response**:** AMPA believes that the primary impediment to deployment of storage technology is cost and the related impact on ratepayers. Other impediments include environmental concerns and uncertainty of value in changing markets and regulatory frameworks.

- ***Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?***

Response**:** AMPA believes that additional value can be derived in day-to-day operations of energy storage facilities. For example, energy storage facilities can be used on a daily basis to essentially trade electric consumption during off-peak hours for generation during peak hours. Energy storage facilities can also be used to offer voltage support and other ancillary services to the grid. The administrative costs of achieving these additional values must be considered as part of the cost/benefit analysis of developing the energy storage facility.

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event?

Response**:** AMPA is unsure of existing dispatch processes used by ISOs to charge energy storage facilities in advance of a storm, or what FERC and NERC allow. In the event of a forecasted extreme weather event, ISOs, in coordination with storage system owners, should be allowed to increase generation in those areas to help the storage systems reach full capacity. Further, assuming coordination with the ISO has been achieved, owners of storage devices should be held harmless from market volatility/penalties during those approved times of energy storage.

- ***Are there constraints or impediments in place that would prevent implementation of such changes?***

Response**:** AMPA is unaware of any constraints or impediments that would prevent the ISOs from implementing changes related to energy storage but acknowledge that FERC and NERC will have oversight of any such changes.

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event?

Response: MEUs are not regulated by the Arkansas Public Service Commission and lack the ability to provide constructive comments on the impact of energy efficiency programs on load shedding.

- ***Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?***

Response: AMPA encourages the Energy Office to adopt policies that discourage electric strip heating as a primary method to control indoor temperatures. Compared to heat pumps, electric strip heating consumes a significant amount of electricity which, in turn, affects the cost of power during winter months. However, while such policies would be beneficial in most circumstances, they would not likely reduce the cost of power during an extreme weather event when secondary sources are required for heat. AMPA encourages the Energy Office to consider energy efficiency rules, targets and programs that financially benefit end users in an amount that reasonably exceeds costs, and implements technology that is both affordable and reasonably available.

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

Response**:** AMPA members did not report using any allocation processes for critical energy resources during extreme events. Thus, the responses below only pertain to preparedness. Similar to the response in question #1, the efforts used by AMPA members to prepare for extreme events varies based on the methods they use to purchase or generate electricity. All AMPA members reported reviewing curtailment processes in preparation of an extreme event.

a. Single provider. AMPA members that depend on a single wholesale power provider for all of their energy, capacity, and ancillary service needs are prohibited from constructing or purchasing power from energy resources that would mitigate the impacts of an extreme event.

b. Contract purchasers. AMPA members using layered energy contracts ("block purchases") to mitigate market exposure will typically increase the volume of purchases when an extreme event appears likely. This strategy reduces the volume of purchases made in the Day-Ahead and Real-Time markets when they are most volatile.

c. Local Generation. AMPA members using their own electric generation assets to mitigate exposure follow checklist procedures to ensure generators will be available when an extreme event appears likely. Some notable procedures used during the recent February winter event are:

i. Insulating main run piping using extruded polystyrene foam with an R5 insulating value;
ii. Insulating valves, pipe functions, filter pots and other sections requiring service access using custom blanketed insulation coverings with an R3 value;
iii. Installing heat tracing cable for water systems have been installed and are a combination of 3W and 5W per foot. Cables consisted of either continuous operation or self-regulating type;
iv. Applying additional heat to liquid fuel regulators; and
v. Applying additional heat and skid coverings to turbine packages and ancillary skids.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Response: AMPA members strive to provide customers as much advance notice as possible when curtailment is required. Curtailment efforts are focused on disrupting the fewest customers for the shortest period of time possible.

Curtailment efforts often start with industrial customers. AMPA members make direct contact with customers to allow industrial systems to be powered down in an orderly fashion. Commercial and residential customers may be notified through a variety of methods. Social media, text messaging, and automated phone calls are common. Some AMPA members also provide cable and/or broadband services that are be used to communicate pending curtailments.

In any curtailment, some customers will request to be exempted based on their particular circumstances. These requests appear to have increased with the increased use of CPA machines. AMPA members that they seek to accommodate requests according to standards that will treat all persons equally. However, not all requests for accommodation can be met. When curtailment is done by opening breakers on distribution lines, individual requests for accommodation by customers on those lines cannot be met. On the other hand, some AMPA members that have installed smart meters with remote-disconnect capability and have more flexibility in managing curtailment at the individual customer level.

III. Summary

AMPA appreciates the efforts of the Energy Resources Planning Task Force to better understand the various causes of increased electricity costs during the February winter event and, more importantly, to develop strategies to mitigate these costs in the future. We are hopeful that our responses to your questions will help you accomplish these goals. We will continue to support the efforts of the Task Force as needed.

TESTIMONY
OF
LIBERTY UTILITIES

PREPARED FOR

THE STATE OF ARKANSAS
ENERGY RESOURCES PLANNING TASK FORCE

APRIL 30, 2021

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

> • In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?
>
> • Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?
>
> • What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

<u>LIBERTY RESPONSE</u>

In the Company's opinion, the primary causes of the electric power shortage in Arkansas during the February winter event were the following: 1) the historically extreme weather conditions (cold temperatures and large snowfall amounts); 2) record-breaking peak demand because of these conditions; 3) fuel supply disruption and shortages, particularly in natural gas; 4) hampered generator availability; and 5) diminished transmission capability.

The Company undertook the following mitigation strategies: 1) curtailment of large industrial and commercial customers; 2) issued periodic peak advisories (social media and other communication channels) to both residential and commercial customers throughout the duration of the event asking customers to conserve energy; 3) implemented controlled interruptions of service to a limited amount of customers (typically in 1-hour blocks); provided outage updates to customers regarding the actions being taken by the Company.

Regarding additional strategies that could be employed in the future to further enhance the Company's ability to provide sufficient power during an extreme weather event, the Company believes that both improved weatherization of critical fuel supplies, particularly natural gas, and improved weatherization of generating facilities would be beneficial. The facts surrounding the February winter event and causes related to fuel supply disruption hampered generator availability and diminished transmission capacity are still being reviewed. As additional information is received, other strategies may be developed to enhance the Company's ability to provide sufficient power during an extreme weather event.

There are other events that could impact electric power availability. Some examples include as acts of terrorism, acts of war, and natural disasters such as earthquakes, floods, and tornadoes.

Regarding additional strategies, regulations, protocols and/or policies that should be developed by the industry or the government to insure Arkansas has an adequate power supply, in the Company's opinion, the electric industry should continue to strategize with stakeholders as to issues such as the future generation mix, advanced planning for extreme weather events, demand-side management, and technologies that improve reliability.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

LIBERTY RESPONSE

In the Company's opinion, steps that can be taken to ensure that the current electric generation capacity mix can provide sufficient generation to serve peak load include both improved weatherization of critical fuel supplies, particularly natural gas, and improved weatherization of generating facilities.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

LIBERTY RESPONSE

In the Company's opinion, changes to the electric generation capacity mix over the next decade will have to take into consideration the requisite reliability and availability of this particular mix of resources under any extreme condition. This could include technological advancements in generation, transmission and distribution, ensuring adequate supplies of the required fuel (excluding wind and solar), advanced event planning, grid modernization, and future on-grid/off-grid usage considerations (residential/community solar, micro-grids, etc.).

4. **Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?**

LIBERTY RESPONSE

In the Company's opinion, reasonably available storage solutions for electricity in Arkansas are being evaluated. Pumped hydroelectric storage may be available for some electric utilities in Arkansas, but Liberty does not have access to these facilities with its current run-of-the-river hydro facility, Ozark Beach. Viable, industry grade, battery storage technology is continuing to improve and Liberty will be evaluating its potential in its upcoming Integrated Resource Plan ("IRP") in Missouri (expected completion April 2022). As discussed in DR 0005, storage solutions have value in the existing market construct for such things as Day-Ahead and Real-Time market price arbitrage, ramp products, and operating reserves. However, investment signals related to additional reliability-based products and the continuing advances in technology that extend capacity and life and lower costs for battery storage would likely lead to quicker adoption of energy storage.

5. **What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?**

LIBERTY RESPONSE

In the Company's opinion, and assuming adequate and reliable storage systems are in place, integrated system operators would have the capability to dispatch additional generation for storage in advance of anticipated emergency events. Ideally market products would be created through, in Liberty's case, the Southwest Power Pool ("SPP") working group process that would send the correct investment signals to market participants. Without specific market product design for the purposes of storage to serve reliability, investment will only occur when value can be created from existing market products like price arbitrage and/or market ramping products. A focus needs to be placed on the blending of economic signals for reliability-based needs.

6. **To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?**

<u>LIBERTY RESPONSE</u>

For Liberty, the implementation of energy efficiency programs in Arkansas had a minimal impact on reducing the need to shed load during the February weather event. The impact of energy efficiency programs was a reduction of approximately 0.2% of energy sales in Arkansas in 2019.

Regarding any changes that could be made to energy efficiency rules, targets or programs, energy efficiency targets could be changed and programs could be increased. However, any increases in these areas would have to take the associated costs and impacts on customer bills into consideration. Just as the current impact on load is minimal, the current cost impact on customers is minimal. The current cost impact is roughly $2.00 a month for residential customers.

7. **Describe your preparedness and allocation process for critical energy resources during extreme events.**

<u>LIBERTY RESPONSE</u>

Transmission Operations
Multiple internal calls occurred in relaying the intent of the effort, revisiting/refreshing the "Emergency Operations Procedures ("EOP") Manual (specifically Section 7) as it related to the possibility of entering a load shed event and providing lists of the load shed blocks within the EOP manual to Line Operations so that they could position personnel to respond to unforeseen issues that are typical in cold weather events. Internal contact information was shared and internal points of contact were identified so that the conveyance of information would be as efficient as possible. Next, The Empire District Electric Company ("EDE") held calls with a neighboring utility (Evergy, formerly Westar ("WERE")) on a co-owned transmission line which has historically been the most congested path on a Market-to-Market basis. These efforts occurred over the weekend preceding the extreme temperatures and were in anticipation of

heightened transfers which would be required between the two markets of impact/interest (SPP & MISO). The transmission line of specific interest was the shared 161kV line between EDE's Riverton station to that of WERE's Neosho station. Both entities agreed to an increase in the rating of this facility by approximately 25%. EDE's intent was to ensure our customers would have access to as much energy as possible should contingencies occur on both the transmission system(s) and/or the generation units. EDE's efforts also ensured that generation on the western portion of our system would be load serving/supporting versus allocated to offsetting of congestion during heightened demand. EDE was glad to support our customers in taking these actions at the forefront.

T&D Operations

Several days in advance of the weather event, Liberty T&D operations personnel began monitoring the load at several critical substations. Operations Managers directed the manipulation of load on several distribution circuits to mitigate the possibility of circuit interruption due to overloading, or load imbalance. Substation operations personnel inspected and made operational any heating devices associated with all substation equipment. Gas levels on station transformers were verified as satisfactory and adjusted as necessary.

Due to the pandemic, line and substation personnel are beginning their work shifts from home utilizing company vehicles as transportation to and from their home base to the job site. Response time to outages is diminished due to the absence of travel time to a service center where company vehicles are normally housed. In advance of the winter weather event, Operations leadership changed the work shift of select crews across the service territory to an earlier start as to have operations personnel ready to respond to any system disturbance as the load increased.

Generation Operations

Throughout EDE's generation fleet there were multiple steps taken to ensure we were as prepared as possible. Some actions were taken during original construction and design and others were more short-term. For example, we purchased the low temperature option on the wind turbines which is designed to maintain adequate oil temperature to allow operation to – 30 C (-22F). The ambient temperature never dropped to this level, and as a result, none of the turbines tripped due to low temperature protection in the cold weather package. At other facilities we reviewed our cold weather procedures, confirmed operation of freeze protection, and confirmed inventory of temporary heat trace supplies. During previous planned outages in the fall we installed skirting in preparation for winter, per our normal outage procedures and other facilities went through their plant winterization list. Also, cold weather operation was a point of emphasis throughout each day and at each shift turnover. Lastly, we implemented a plan last year to carry 10 days of fuel oil at one of our dual fuel units and another 7 days of fuel oil at our other facility that has dual fuel capabilities.

Power Marketing/Fuel Procurement

After the first week of February, as weather forecasts began to predict more extreme temperatures, Empire procured additional fuel sufficient to operate Riverton Combined Cycle and State Line Combined Cycle at their maximum output . Additionally, prior to the period, the fuel oil tanks for State Line Unit 1 and Energy Center Units 1 – 4 were at full capacity with enough fuel oil to operate the dual fuel units at full capacity around the clock for seven (7) and ten (10) days respectively. Throughout the period, Company personnel monitored and analyzed natural gas cut notifications (received over 300 cut notices between February 6th and February 19th) and adjusted plant operations as necessary to maintain operational reliability and minimize the potential financial impact of over-delivery, including Operational Flow Order (OFO) penalties.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

RESPONSE

Empire has processes defined and prescribed in our Emergency Operations Procedures ("EOP") manual for the implementation of curtailments and load shedding. Curtailments are defined as a Code Yellow event and occur on an as needed basis due to system conditions warranting the alleviation of load from Empire's system or when instructions are received from the Regional Transmission Organization ("RTO") due to grid conditions. Conditions requiring curtailments and load shedding include, but are not limited to, Energy Emergency Alert ("EEA") Level 2 Alerts issued by the RTO, conditions established by the North American Electric Reliability Corporation ("NERC"), emergency situational awareness, Transmission Operator determination, and RTO instructions. The implementation timeline of curtailments is dependent on the nature of the grid conditions at the time of the need. Empire Operators and/or Empire management will decide when a Voluntary Load Reduction Plan will be implemented and notify internal personnel of the need so that customers can have adequate time to voluntarily reduce their load. These loads generally consist of industrial customers which have the ability and have agreed to reduce their load upon notification from Empire personnel. In addition to voluntary customer curtailment, Empire makes internal notifications to company facilities to eliminate all non-essential consumption to support the overall load reduction efforts. Finally, Empire makes public appeals to its customers to reduce load across the entire system through various available platforms such as direct email notifications to customers and social media posts.

Load shedding is implemented under Code Red events based upon emergency conditions such as the inability to serve load on a local Operator level if the Transmission Operator determines there is inadequate transmission or generation capacity available to serve the load present on the system. Similar declarations can be made by the RTO under an EEA Level 3 Alert when operating reserves are below required minimum levels. As a result, the RTO prescribes the gross amount of load each entity is required to shed (typically on a Load Ratio Share of the shortfall present within the RTO Regional assessment).

Transmission Operators utilize pre-determined blocks of feeders to deenergize, with each block generally consisting of approximately 50MW of load available to be shed. As many of the blocks as needed (including partial blocks) are implemented to meet the gross MW requirements of the load shed event. The blocks are determined by way of previous circuit analyses to avoid deenergizing both public support functions as well as critical customers. Critical customers include, but are not limited to, hospitals, nursing homes, water treatment plants, fire/rescue/police, jails, communication hubs and warming/cooling centers. Empire makes every attempt to avoid impacting these customers in an effort to best support the general public, but cannot guaranty facilities will be insulated from possible impacts from a load shed event as system conditions and directional flows may change over the course of time. Empire also compiles the blocks so as to not cluster feeders within a common geographical area so that customers on feeders which have been deenergized will have alternative means to seek help should the need arise. Empire also makes every attempt to ensure entire communities are not disconnected so that an entire region is not impacted, but rather that the impacts are spread out throughout the entire service territory. The final vetting process makes every attempt to not overlap the Underfrequency Load Shed circuits. This effort helps to ensure the resiliency of the network should frequency start to deteriorate across the local and/or Regional systems. In doing so, this ensures the integrity of the network as best possible during times of rapidly changing, highly compromised infrastructure (inability of generation, transmission contingencies, etc.).

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OG&E

May 7, 2021

Arkansas Energy & Environment
Energy Resources Planning Task Force
Email: ERPTaskForce@adeq.state.ar.us

Dear Energy Task Force:

In response to the Energy Resources Planning Task Force's ("Task Force") email dated April 9, 2021, Oklahoma Gas and Electric Company ("OG&E) hereby submits its responses to the Task Force's Testimony Questions, as follows:

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:
   - In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?
   - Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?
   - What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

Response: OG&E is a member of the Southwest Power Pool ("SPP"). "SPP is a regional transmission organization ("RTO"): a nonprofit corporation mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its members ."

SPP is responsible for the development and oversight of policies and procedures related to reliable supply adequacy within its footprint including ensuring that the policies and procedures meet the compliance obligations of North American Electric Reliability Corporation ("NERC") Reliability Standards. The primary cause of the power shortage was the significantly cold temperatures that covered the middle of the continental US including the entire SPP region for approximately a week. This week-long event put significant demand on *all* generation resources of all fuel types and technologies and, required them to operate in extreme weather conditions beyond their typical operational conditions.

These conditions resulting in generation unavailability due to lack of fuel supply and icing and extreme cold weather-related outages; rapid reduction of energy imports from neighboring ISOs as a result of transmission congestion and tightening supply conditions in neighboring areas and; record wintertime energy consumption[1].

Throughout the event, SPP remained in communication with its members and utilized various tools to mitigate and prevent as possible, the need to take customers offline. These tools include,

- The use of the Emergency Action Alerts (EAA) which provided notice of current conditions and actions that needed to be taken by operators and members including the need to: delay or defer planned outages for maintenance, return those generation units in outage back to service as possible, curtail 'interruptible' large customers, issue public appeals for energy conservation, relieve transmission congestion and constraints as possible
- Importing energy across the SPP's seams as possible to supplement the native supply and meet the needs of the region's customers.
- Shed customer load as directed as a matter of last resort

These tools were used throughout the week-long event in cycles according to the changing weather conditions and the physical, operational condition of the system including the generators and transmission.

SPP is in process of conducting a multidisciplinary after-action review of the event and is expected to present its report to its board of directors in July. At that time, SPP and its membership will evaluate the findings and develop any needed course of actions. It would be inappropriate to speculate on specifics at this time.

It can be said as a general observation that a diversity of fuels and demonstrated technology in addition to interconnected electricity grids proved invaluable to minimizing the extent of the customer outages that were required.

There are a number of potential events both natural and manmade that could result in inadequate power availability ranging from wildfires to earthquakes to a terroristic attack however, the degree and nature of the potential impact of such events to the system and the ability of the system to respond would be speculative.

With regard to this event, it is premature to speculate until the SPP reports its findings of the after-action review. As a general matter, this event supports the need for sound energy policies, practices & regulation that do not preclude or prematurely foreclose certain energy sources or technologies and, enable market structure and economics to work.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response: The SPP electric generation capacity mix includes primarily natural gas, coal, nuclear, solar, wind, hydro, fuel oil resources. OG&E's maintains and operates natural gas, coal, solar and wind resources. As stated in SPP's Grid Emergency Presentation (please see attachment 1), SPP's "diverse generation mix gave flexibility during storm response." Fuel diversity is a key factor in dealing with uncertainties for weather, fuel supply and cost.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response: SPP is responsible for performing the Loss of Load Expectation ("LOLE") Study[2], which it relies on to determine the planning reserves needed to maintain the reliability metric guidelines specified by NERC. SPP is

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[1]Taken from the SPP BOD material, March 2021 and available at: https://spp.org/documents/64239/special%20bod%20mc%20minutes%20and%20attachments%2020210302.pdf

[2] Available at: https://www.spp.org/documents/62810/2019%20lole%20study%20report.pdf

implementing Effective Load Carrying Capability ("ELCC") as the guiding principle for capacity accreditation of wind, solar and storage resources in SPP so that the intermittent nature of these resources will be considered for accreditation. SPP's ELCC wind and solar white paper states "As the penetration of wind and solar generation increases, SPP and its members need to be aware of and understand the changing impact these resources have on the economics of resource adequacy and on the reliability of the system[3]." SPP, in collaboration with its members, continues to review resource accreditation methodologies for all resources in order to maintain reliable supply adequacy within the SPP footprint.

OG&E in engaged in the development and review of the SPP studies and utilizes the information in each company integrated resource plan. OG&E strives to develop a resource plan that will allow it to meet its capacity obligations over the planning horizon at the lowest reasonable cost with due consideration of the uncertainties attributable to many of the planning assumptions and other items of value to OG&E customers. As the electric generation capacity mix is expected to change in the future, OG&E's objective of fuel diversity maintains a reasonable balance among natural gas, coal and economically viable renewable, energy storage and demand-side resources. Additionally, OG&E's objective of resiliency benefits considers generation capability to minimize disruptions.

4. Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

Response: There are commercially available battery solutions; however, they are still price prohibitive. OG&E continues to evaluate the reasonableness of deploying batteries and monitor costs which are decreasing and expected to reach more reasonable levels in the coming years. It is also important to note the amount of battery storage required to support OG&E's Arkansas territory through extreme weather events, such as the one experienced in February 2021, would be exorbitant both in scale and cost.

There are several barriers that could hamper the swift deployment of battery storage. First, although increasing, there are currently a limited number of utility-scale battery manufacturers. Second, each bank of batteries is considered its own system requiring specific engineering and the associated Battery Management System ("BMS"). Third, since each bank has its own specific requirements, each system is constructed only after purchase (i.e. there are no off-the-shelf utility-scale batteries). Fourth, a battery built to support power is not equipped to provide long-term energy backup. Finally, the rules on how energy storage will participate at the wholesale level are evolving with two FERC cases, 2222 and 841 and their effect on the Southwest Power Pool.

The following are some examples that battery storage may be used for during day-to-day operations. Batteries installed near generation sources can manage the inherent instability of renewable resources by storing and re-dispatching energy when the wind doesn't blow, and the sun doesn't shine. Batteries located near transmission substations may allow OG&E to store energy near the generation source from "Must Run" facilities, like wind, when transmission congestion is high and re-dispatch the energy when congestion eases. Batteries located across the distribution system near customer loads provide backup power, peak load support, power quality, reliability and resiliency for customers, fast charging for long-haul transportation, and storage for individual net metering customers.

Batteries that qualify to be multi-tasked for other day-to-day functions must use caution to ensure it does not deplete the necessary energy needed in case of any unplanned event rendering its ability to provide backup power.

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[3] Available at: https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?

Response: Currently, OG&E does not have any pump or battery storage on its system.

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

Response: Since program inception, 2008, 193,580,769 kWh savings has been achieved through OG&E's energy efficiency programs in Arkansas. We could deduct that in the absence of the energy efficiency programs, customers would have consumed the additional kWh, resulting in a greater amount of load shed needed. There are many other variables to be considered, therefore we cannot say with certainty the impact of energy efficiency on reducing the amount of load shed needed. We do not see a need to change the rules.

Table 1-1 Historical Annual Incremental EE Savings Achieved				
Program Year	**Energy (kWh)**	**% Increase from Prior Year**	**Demand (kW)**	**% Increase from Prior Year**
2008	2,434,738		666	
2009	5,607,951	130%	921	38%
2010	4,143,096	-26%	1,317	43%
2011	4,985,328	20%	1,520	15%
2012	7,595,741	52%	1,840	21%
2013	13,410,729	77%	2,797	52%
2014	13,794,070	3%	2,883	3%
2015	20,543,040	49%	3,115	8%
2016	23,257,181	13%	3,434	10%
2017	21,130,663	-9%	3,396	-1%
2018	22,556,832	7%	3,974	17%
2019	26,071,158	16%	4,591	16%

2020	28,050,242	8%	4,878	6%
Total	**193,580,769**		**35,332**	

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

Response: Please see the response to Question No. 2.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Response: Once SPP notifies OG&E of the potential for load curtailment, OG&E immediately begins communicating to customers load curtailment may occur without additional warning and encourages customers to prepare for the possibility of service interruptions. These notifications are made in conjunction with continued calls for conservation and occur through the following methods:

- Issuance of press release(s);
- Posting "emergency banner" with messaging on company web site, OGE.com;
- Posting messaging to all OG&E social media channels; and
- Emailing customers with messaging.
- Media interviews (television, radio, newspaper, etc.)

Once OG&E receives a curtailment directive from SPP, the load shed must begin immediately leaving inadequate time to specifically notify customers in advance of interruption. OG&E makes every attempt to communicate with affected customers through email and social media to make them aware of the cause of the interruption as well as expected time of restoration. The immediate need to begin curtailment also makes a formal appeal process very difficult. Fortunately, OG&E's curtailment plan aims to avoid interrupting circuits with customers performing critical functions such as hospitals or water treatment centers. OG&E's managed account representatives and community affairs personnel are also in constant contact with customers, particularly those performing critical functions. Although the company seeks to minimize disruption to customers and will continue to seek ways to enhance customer communications in all events, advanced notifications and customer opt out preferences in a curtailment event cannot be considered to the detriment of maintaining the overall reliability and integrity of the grid.

Respectfully Submitted,

Kimber Shoop
Director of Regulatory Policy & Planning

Enclosure: Attachment 1