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PREPARED COMMENTS OF DONNA WALKER PRESIDENT/CEO,
HOOSIER ENERGY RURAL ELECTRIC COOPERATIVE, INC.
ON BEHALF OF THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

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INTRODUCTION

HOOSIER ENERGY

Hoosier Energy, on behalf of NRECA, appreciates the opportunity to participate in today's technical conference regarding energy resource adequacy and expected load growth within the United States. Hoosier Energy is a not-for-profit generation and transmission electric utility (G&T) with headquarters in Bloomington, Indiana. The G&T is owned and governed by 18-member distribution cooperatives in central and southern Indiana and southeastern Illinois, serving more than 760,000 consumers across a 15,000-square-mile area.

Hoosier's vital mission is to provide our member distribution cooperatives reliable and economically priced energy and member-driven services. We are also committed to meeting our members' evolving needs in a safe and sustainable manner, guided by the seven cooperative principles.

Additionally, Hoosier Energy provides transmission services to our members either across our own transmission system or the transmission system of neighboring utilities. Our transmission infrastructure encompasses approximately 1,730 miles of transmission lines, interconnecting with seven other electric utilities. Hoosier is a member of MISO and PJM.

As a general premise, electric cooperatives rely on a diversity of resources to affordably and reliably meet their consumer-members' energy needs. Because of their comparatively small size, cooperatives rely on fewer generation resources than other segments of the utility sector. Any actions affecting the availability of these resources disproportionately impact cooperatives and their consumer-members. It is important to note that electric co-ops serve some of the most economically challenged communities in Indiana and Illinois. Hoosier Energy is home to numerous federally designated disadvantaged communities, and our members take great care in serving those on fixed and limited incomes.

Electric cooperatives continue to increase the use of renewable energy resources; leverage distributed energy resources and storage; adopt energy efficiency programs; monitor and explore developments related to nuclear energy; and work to enable an electrified economy.

For its part, Hoosier draws power from a diverse range of resources and has made significant strides over the last decade to increase renewable energy production and distribution. Our commitment to renewable energy has been bolstered by a voluntary board policy to increase the renewable portion of our production to at least 10% by 2025. In 2022, our energy mix was 71% coal, 9% renewables and 20% natural gas. By 2030, we project that our mix will be 4% coal, 15% renewables, 48% natural gas, and 33% nuclear from the recommissioned Palisades Plant in Michigan.

NRECA

The National Rural Electric Cooperative Association (NRECA) is the national trade association representing 900 not-for-profit local electric cooperatives and other rural electric utilities. America's electric cooperatives are built and owned by the people that they serve and comprise a unique sector of the electric industry. From growing regions to remote farming communities, electric cooperatives power one in eight Americans and serve as engines of economic development for 42 million Americans across 56% of the nation's landmass. Electric cooperatives operate at cost and without a profit incentive.

NRECA's member cooperatives include 63 G&T cooperatives and 832 distribution cooperatives. The G&T cooperatives generate and transmit power to distribution cooperatives that provide it to the end-of-line co-op consumer-members. Collectively, G&T cooperatives generate and transmit power to nearly 80 percent of the distribution cooperatives in the nation. The remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. Both distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

These remarks are provided through the lens of NRECA's members.

As is the case with Hoosier Energy's owner-members, many cooperative consumers are among those least able to afford higher electricity rates. In 2023, the average (mean) household income for electric cooperative consumers was 12% below the national average. That is unsurprising, given that electric cooperatives serve 92% of persistent poverty counties in the United States.[1] Since electric cooperatives serve areas with low population density, costs are borne across a base of fewer consumers and by families that spend more of their limited resources on electricity than do comparable municipal-owned or investor-owned utility customers.

AFTERNOON SESSION PANEL 2: RESOURCE ADEQUACY AND EXPECTED LOAD GROWTH

Panel 2: Resource Adequacy and Expected Load Growth

The retirement of existing generating resources, the addition of significant volumes of variable energy resources, and rapid anticipated electric load growth present challenges for system operators to maintain resource adequacy. This panel will explore the drivers of expected new demand, such as data centers, and examine whether and how existing resource adequacy mechanisms are prepared to accommodate the potential for significant new demand. The panel will also explore how these challenges are driving transmission system operators and planners to evolve long-standing approaches to maintaining resource adequacy.

Hoosier Energy, on its behalf and that of NRECA, appreciates the opportunity to discuss the status of resource adequacy now and planning for it in the future. Hoosier Energy and NRECA's overall position is that an "all of the above" policy on resources has never been more critical to maintain reliability, predicated in large part on unprecedented challenges.

The value and importance of electricity have never been greater. The global energy transition is a major part of a larger social transformation. The world is looking to electricity – to us – to reliably power the rapid advancement of the digital economy while also replacing fossil fuels. The world adds a new data center every three days. Electricity is the key input that determines the profitability of these data centers, and the amount of energy AI requires is astounding. The rapid addition of domestic manufacturing facilities, including microchip and battery production, requires significant energy resources as well. The increasing emphasis on and demand for electric vehicles, and the energy necessary to charge them, are other examples of factors contributing to the growing need for electricity.

The electric grid is already struggling to keep up with existing demand. Recent NERC reliability assessments have pointed to "the disorderly retirement of traditional generation (with its inherent ability to provide essential reliability services and balance energy reserves) as one of the biggest challenges facing the grid."[2] NERC has also declared that "[c]lose coordination will be needed among regulators, policymakers, and industry to ensure that sufficient electricity resources will be available to meet rising demand and grid reliability needs. Regulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability.[3]

NRECA has been clear about the need for smart energy policy to prioritize electric reliability. Resource adequacy is a critical component of maintaining reliability, and policymaking is impacting our members' ability to reliably and affordably provide power to the 42 million Americans they serve.

At the same time, we are being asked to provide electricity that is itself more sustainable in ways that are more consumer focused. This directive comes from administrations, policymakers, regulators and most importantly – member-consumers.

Hoosier Energy exemplifies the co-op commitment to maintain both a diverse portfolio and affordable, reliable service for all consumer-members during periods of challenges to the industry: exponentially high load growth, regulatory-driven curtailment and retirement of baseload assets, transmission constraints, supply chain obstacles, and an increased need for gas/electric interdependency propelled in no small part by more frequent extreme weather events.

What has Hoosier Energy done to date? For starters, we have been able to reduce our carbon emissions by nearly 40% since 2005, with steeper reduction anticipated in the near future.
In early 2020, after a year of careful consideration, the Hoosier Energy Board of Directors made the strategic decision to step away from ownership of the coal-fired Merom Generating Station and move toward a more diverse, sustainable, stable, and affordable resource mix for the future. This commitment was the springboard for transforming our power supply portfolio. It opened new possibilities and opportunities for the future.

In the four years following that decision, we've encountered a global pandemic and massive supply chain disruptions. Inflation hit a 40-year high. Russia invaded Ukraine setting off a global energy crisis. Extreme weather events have become more frequent. Retirements of dispatchable fossil generation have outpaced replacements, and those replacements have largely been in the form of intermittent wind and solar, which are also vulnerable to extreme weather events.

With fewer readily dispatchable generating resources, the margin of error is extremely small as we transition the nation's energy mix. This raises serious concerns about the reliability and adequacy of electricity supply in many regions of the country.

What are Hoosier's plans for the future and what are the primary factors driving those plans?

Hoosier Energy is working hard to transition from a primarily baseload coal-fired generation utility to a more balanced portfolio. However, we recognize that in order to continue to supply our members with affordable and reliable energy, we must find alternative baseload and intermediate resources (such as natural gas-fired combined cycle and simple cycle facilities) to act as the backbone of our portfolio strategy while supplementing these resources with more intermittent types of resources, such as solar and wind.

As part of this process, we partnered with Wolverine Power Cooperative on power purchase agreements with Holtec International from the Palisades Nuclear Generating Station, a carbon free, baseload resource that will produce reliable, affordable energy and capacity for our members. We are also pursuing the purchase of an existing combined-cycle facility – in partnership with another G&T cooperative – that will supply necessary capacity and energy. Meanwhile, we continue to pursue power purchase agreements with solar and other renewable resources as the opportunity arises. We now have substantial resources in place to meet members' capacity needs through 2032 and continue to actively pursue supply opportunities for 2033 and beyond.

The resource additions are all as needed to supply a normal/typical expected load growth over the next 10-20 years. These efforts become much more complicated when considering the vast number of moving parts within our industry. The process of measuring reserve requirements has changed, with MISO now looking at calculating reserve requirements for resources over four seasons rather than annually. This means that each resource receives a different capacity accreditation for each season rather than a single, annual accreditation, while also increasing reserve requirements.

As discussed subsequently, changes in customer load, especially large customer loads, have the potential to turn resource adequacy on its head. Hoosier Energy is by no means alone among the co-ops in receiving interest from data centers, artificial intelligence and cryptocurrency companies.

1. ***What combination of metrics are most appropriate to capture resource adequacy risk beyond the traditional planning reserve margin? What further actions should the Commission, NERC, states, and others take to promote their use?***

Within this context, Hoosier Energy construes "metrics" to refer to plans or models that form the basis of Integrated Resource Plans (IRPs). Historically, utilities, including Hoosier Energy, had developed processes that were able to reliably predict and forecast customer/member load growth, which typically grew at a relatively stable and slow rate over time. However, given the changes facing the industry (as discussed earlier), it is unclear whether or not the traditional tools used to develop the IRP will continue to provide a reliable picture of the future load growth for Hoosier Energy.

As an example, in the last IRP filed by Hoosier Energy, the Hoosier system was forecast to experience load growth of approximately 1% each year for the forecasted period. This load growth would typically occur incrementally among the member systems with relatively small additions at one time. Now, however, Hoosier is seeing projects that wish to develop as much as 1,000 MW of demand and energy needs (which for a 1,700 MW peaking utility is substantial) in a short period of time.
And Hoosier is seeing not just one of these projects, but several at any given time. For a utility that

would typically add 20-40 MWs of new load growth per year, adding just one such megaload has important ramifications to Hoosier Energy and its member systems with regard to procuring resources to serve the load and developing sufficient transmission to deliver those resources to the load. Hoosier Energy has been working with its member systems to develop an effective strategy to serve these expected megaloads, while working within the current parameters of state regulations and MISO rules and processes.

Resource adequacy should not be viewed as a line in the sand. The objective must be to strike a balance between cost and reliability. Planning reserve margin, as it was traditionally considered, was adequate for many years when almost all resources were dispatchable. Even then, one had to consider the proper resource types for the portfolio margin to ensure the loss-of-load expectation (LOLE) criteria was met. However, because we are facing rapid load growth, plant retirements, and a shift toward variable and energy-limited resources, the resource adequacy criterion will likely need to change, or at a minimum be augmented.

A potential addition to incorporate the size of shortfalls as the system moves toward energy limitations is expected unserved energy (EUE). A first step to better differentiating resource adequacy shortfalls is adding EUE as a resource adequacy criterion. EUE measures the expected (*i.e.*, average) amount of unserved energy per year, averaged across all resource adequacy simulations. A first benefit is that, all other things being equal, EUE places a greater emphasis on larger, more disruptive events, a critical consideration in differentiating shortfalls. A second benefit of EUE is that it explicitly measures power system energy limitations— an important consideration as the system becomes more energy-constrained (due to increased storage and load flexibility) and is not just capacity-constrained. EUE also aligns well with economic metrics, as the value of lost load (VoLL) and other cost metrics are often expressed as $/MWh, facilitating a more straightforward translation between reliability and cost objectives.

Again, the essential element that must be taken into account is the trade-off between cost and reliability. At the end of the day, no one metric is the solution; a multi-metric framework is needed to consider size, frequency, and duration of shortfalls.

FERC would benefit from considering the cumulative impact of all of these factors when evaluating the reliability risks of today and how it can avoid exacerbating those risks. Electrifying other sectors of the economy could require a three-fold expansion of the transmission grid and up to 170% more electricity supply by 2050, according to the National Academies of Sciences.[4]

2. ***Discuss the drivers of anticipated increased load growth. What are the challenges and uncertainties inherent in forecasting the addition of new, large loads, including data centers? How do those challenges differ from traditional challenges in load forecasting?***

I discussed the drivers on anticipated load growth earlier in my testimony. With respect to the challenges and uncertainties inherent in forecasting the additions of this new load, we have to acknowledge the impact on generating resources caused by the EPA's recent power plant regulations: Attributes needed to ensure reliability will become scarcer.

Just recently, the regional grid operators responsible for maintaining reliability on the bulk power grid across 30 states echoed this concern in their amicus brief in the EPA power plant rule litigation. SPP, MISO, PJM, and ERCOT stated, "the compliance timelines and related provisions of the rule are not workable and are destined to trigger an acceleration in the pace of premature retirements of [plants] that possess critical reliability attributes at the very time when such generation is needed to support ever-increasing electricity demand because of the growth of the digital economy and the need to ensure adequate back-up generation to support an increasing amount of intermittent renewable generation."[5]

Based on permitting timelines, grid operation interconnection challenges, limited construction vendors and other variables, sustainable generation cannot be constructed in time to replace the viable resources being retired and curtailed. This is exacerbated by the uncertainty of future environmental regulation of existing and future gas generation. There will be very little incentive for cooperatives to invest in the power plant rule's nascent technologies at exorbitant costs – as those costs would be borne by our consumer-members – all at a time when resource adequacy and reliability are already challenged in many regions by other generator retirements and other factors.

Under the power plant rule, state plans for existing generating units would be due in the summer of 2026, placing inordinate pressure on utilities to make crucial generation and retirement decisions in a brief window of time, while challenges to the rule are likely to still be working through the court system. There will not be sufficient information on the advancement of proposed technologies by 2026 to know what will reliably work in the early 2030s. Implementation of the power plant rule will greatly impact the ability to maintain reliability with an influx of new, intermittent, renewable resources. These resources will not address reliability impacts driven by the expected retirement of significant volumes of existing baseload fossil fuel generation, nor does the rule take into account the operation of new generating resources at lower capacity factors.

Moreover, NERC has warned that for many regions of the country, the additional retirements of baseload thermal power plants – if not replaced by dispatchable, flexible resources – will increase the risk of rolling blackouts. As NERC correctly points out, "merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load."[6] NERC recommends that policymakers and industry manage the pace of generator retirements until solutions are in place to meet energy needs and ensure reliability.

The impact of the entire suite of EPA and other federal agency actions on the power sector and baseload fossil resources must be taken into account, including steam ELG, CCR, Ozone Transport, NAAQS, NEPA, etc. NERC identified the ozone rule as one of the key reliability issues for grid operators to watch.[7] NERC "pointed to the disorderly retirement of traditional generation (with its inherent ability to provide essential reliability services and balance energy reserves) as one of the biggest challenges facing the grid."[8]

Large Single-Site Load Additions and Incremental Load Growth

In 2022, no single Hoosier customer constituted more than 3% of our members' aggregate billing, and no single co-op member constituted more than 10% of Hoosier's total sales. Growth for electric cooperatives has traditionally been linear and incremental, ensuring reliability, affordability and security for cooperative members. That dynamic has completely changed. An increasing number of projects coming in are now larger than 25 MW (with multiple exceeding 1,000 MW or more), with many prospects seeking or requiring uninterruptible, 100% renewable energy. For perspective, Hoosier Energy's peak forecasted load in 2023 was 1,650 MW total.

Large, single-site load additions such as data centers, are an urgent challenge. The dynamics of these large loads are very different than in the past when load growth or decline was tied to changes in GDP, population, and DOE efficiency standards, such as those for HVAC, appliances, and lighting. Forecasting these additional loads can be challenging because they are tied to multiple corporate decision-making criteria and technologies, such as AI, which are rapidly changing.

Megaload customers want rapid responses while the utilities must guard against stranding investments. Given the size, structure, and renewable-energy focus of most of these new projects within the last year, we have concerns about the ability to successfully meet the requests. Additionally, the level of investment to meet such requests in rural/suburban areas can equate to tens of millions of dollars per project, thereby creating serious challenges when combined with the demands of prospects, site selectors and other stakeholders. In order to meet the aggressive timetables, utilities are being asked to take unsecured risks, putting native load ratepayers at risk of covering costs if the projects do not come to fruition.

The surge in megaload projects also highlights the need for transmission upgrades and interconnections in particular. Hoosier recently formalized its own internal interconnection process to manage the influx of prospective projects greater than 50 MW each.

The Commission is well aware of the other challenges confronting reliability of the bulk electric system:

Extreme Weather: In late 2022, Winter Storm Elliott illustrated the imminent danger of grid emergencies and the need for reliability contingencies. The weather event caused a significant generation shortfall. During the storm, Hoosier Energy was impacted in several areas, including natural gas production and delivery. Local gas distribution companies had a first priority to serve retail gas customers, not gas-fired generators.

Supply Chain Constraints: Electric utilities are facing significant challenges and delays in their supply chains. These challenges are contributing to an unprecedented shortage of the most basic machinery and components that are essential to ensuring continued reliability of the electric grid. Whether it is unprecedented delays and ballooning costs for distribution transformers, large power transformers or electrical conduit, new projects are being deferred or canceled, and cooperatives are concerned not only about their ability to respond to major storms due to depleted stockpiles, but also about their ability to obtain new transformers and equipment needed to serve increasing load demands.

Gas/Electric Interdependence: Another concern respecting the interdependence between natural gas and electricity is a structural market design issue that involves the reliance on markets for commitment of generation resources. The organized market rules have *de facto* removed the obligation to serve from the generators in their markets due to an increase financial risk from a Load Serving Entity (LSE) making a commitment decision outside the market operator instruction and no reduction in reliability risk from such a decision.

An LSE that owns generation is disincentivized from procuring natural gas and committing generation on its own. If the market operator ultimately determines that the unit was not needed and the natural gas market shifted dramatically, the LSE faces significant losses with no ability to recover the costs. Further, if the LSE committed its generation and the market was short overall, its load would still be shed on a pro-rata basis, regardless of whether it has covered its own load and reserve obligations. Thus, an LSE is forced to rely on the market to anticipate that load may come in higher during extreme weather conditions. Proactively scheduling long-lead resources and/or developing products that would allow market operators to commit generation in advance of extreme cold events would alleviate this market risk and disincentive toward maintaining reliability.

Permitting Challenges: Electric cooperatives rely on a diverse suite of resources to affordably and reliably meet their consumer-members' energy needs, including many low- and zero-emission renewable energy resources. Policies enacted in the Inflation Reduction Act – particularly the "direct pay" tax credits for not-for-profit entities and USDA's Empowering Rural America (New ERA) program – are expected to help more rural Americans transition to lower-carbon, affordable, and reliable energy. But the promise of these programs will falter if the federal environmental review and permitting process is not modernized to meet the needs of this energy expansion.

Completing federal environmental reviews and obtaining permits for infrastructure projects simply takes too long and presents another challenge to building new electric generating assets and other electric infrastructure, including transmission lines. On average, it takes federal agencies four and a half years simply to complete the environmental review process, while one quarter of projects take more than six years.[9]

3. ***Will existing resource adequacy mechanisms (e.g., centralized capacity markets) be able to procure appropriate and sufficient resources to meet expected future demand? If not, what changes are needed and how should they be prioritized?***

It is hard for markets to correctly structure incentives that fully mitigate resource adequacy risks because the level of incentivization must match the level of risk. A tariff mechanism must be in place for each risk, whether for a capacity market or ancillary benefits. The transformation that is happening requires periodic adjustments because all capacity is not the same, and inverter-based resource (IBR) system-supporting technology is rapidly changing.

Indiana has a 15% cap on purchases of RTO capacity. Hoosier Energy participates in both the MISO and PJM markets. We are required to meet generation and reserve capacity requirements of the Indiana Utility Regulatory Commission (IURC) and MISO. The IURC purchasing cap recognizes too great of a reliance by utilities on the market capacity in regional transmission organizations (RTOs) – which is currently in a constant state of flux – creating too great of a risk for Indiana ratepayers. Given this rule, Hoosier Energy must "firm up" 85% of its capacity in a market where firm capacity is increasingly difficult to find due to constraints on permitting and developing such capacity. Regardless, capacity is tight in both MISO and PJM, while the closing of generation facilities is outpacing the construction of new generation assets.

Moreover, the backlog and length of time required to move new generation projects through the queues makes it extremely difficult to bring on baseload and intermediate resources as and when needed. There may need to be priority given to LSEs in developing generation capacity to serve their load obligations.

4. ***How can the Commission and states work together to identify and proactively mitigate resource adequacy risks?***

FERC and states must work together on transmission constraints, including reconsideration of the final decision not to have Relevant Electric Retail Regulatory Authorities (RERRAs) – including states and self-regulating entities – participate in cost-allocation methodology. At the end of the day, both the Commission and the states must be realistic about (1) the impact of reforms and the overarching need for regional flexibility to make decisions that actually work within their planning regions and (2) the fact that policies favoring new resources on the grid and grid enhancing technologies such as Dynamic Line Ratings (DLRs) will not replace retired baseload generation, especially given the boom in load growth and the other challenges discussed previously.

States and FERC must focus on consumers.

In FERC's case, under section 217(b)(4) of the Federal Power Act, FERC should focus transmission planning and expansion on meeting the needs of LSEs and the consumers they serve. Towards this end, FERC should work to ensure that ongoing efforts to reform transmission planning and cost allocation policies result in (1) continued availability of reliable service of electricity, (2) comparable treatment of similarly situated customers with respect to terms and conditions and rates for transmission service, (3) efficient and affordable long-term transmission planning and expansion that will be used and useful, focused on the long-term needs of LSEs, and which provide for regional flexibility, and (4) transparent planning and cost allocation processes.

Citations

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