Executive Summary

The focus of this document is resource adequacy in the electric industry in North Dakota. It is written as a primer for stakeholders interested in better understanding policies, jurisdictional authorities, and operational issues that affect resource adequacy. Key findings include the following:

- Given the utility and regulatory structures employed in North Dakota, resource adequacy is a shared responsibility among several entities: utilities, regional transmission organizations (RTOs), regulators (both federal and state), and state policy leaders. North Dakota has certain jurisdictional prerogatives, but its authority is not absolute. It is constrained by decisions made by RTOs, the federal government, and other states as well as commercial and technological changes that are beyond the control of any governmental entity. Smart public policy development will require an understanding of this complex jurisdictional ecosystem.

- In North Dakota, utilities plan for resource adequacy. Unlike Texas, California, and other more fully unbundled utility states, in North Dakota, integrated utilities own generation, transmission, and distribution assets, with the responsibility for planning a system that delivers electricity reliably throughout their service territories. This integrated resource-planning process offers distinct advantages over the other regulatory models.

- Although North Dakota utilities are vertically integrated, they do not operate in a vacuum. They are part of an interconnected, interstate grid that is managed by RTOs. RTO grid-planning initiatives are part of an important feedback loop. While it is incumbent on utilities to appropriately plan to have the resources needed to keep the lights on in their own service areas, that planning must be informed by what is happening in the broader region. If either the RTO or the utility fails to account for these dynamics, there can be a failure to achieve resource adequacy.

- North Dakota has seen significant growth in electricity generation production in the last 20 years, having added more than 4000 megawatts (MW) of nameplate wind capacity to the existing approximately 4000 MW of coal-fired capacity. While North Dakota’s native load has grown over the corresponding period, the state still exports a significant amount of the electricity produced inside its borders.
North Dakota electricity demand is likely to grow significantly over the next 20 years. Energy demand growth in the Bakken and the potential growth in electric vehicles (among other changes) could result in demand increasing by 100% or more under certain scenarios.

The changing dynamics of the grid—especially related to the integration of intermittent renewables and the growing importance of natural gas as a fuel source for generation—has resource adequacy implications that have been identified by the North American Electric Reliability Corporation (NERC) as well as the RTOs themselves. While not insurmountable, the changing grid will require proactive solutions on a relatively quick timeline. The issue is a regional one that extends beyond any one state’s borders. Both MISO and SPP are engaged in processes intended to address these resource adequacy concerns.

The participation of North Dakota’s utilities in RTOs is the result of specific circumstances that argued for regional collaboration to benefit consumers from a cost and reliability perspective. In addition, because North Dakota’s electricity production greatly exceeds native demand, its integration into regional markets facilitates export of an important North Dakota-made product. Nonetheless, the interstate nature of an RTO means that North Dakota’s energy industry is influenced by circumstances and entities that are not exclusively under state jurisdiction.

It is in North Dakota’s interest to fully participate in RTO, regional, and national electricity policy proceedings. North Dakota must be prepared to expend the resources to successfully engage in these matters with RTOs and before the federal government, understanding that the state itself likely has as much influence with the RTOs and the Federal Energy Regulatory Commission (FERC) as any single utility.

Ensuring resource adequacy, including addressing issues related to renewable intermittency, fuel source and transport security, is an issue that utilities, RTOs, and regulators will need to address through several strategies. However, any single state’s attempts to ban or impose state-level burdens on specific multistate RTO resources is unlikely to be successful as a policy prescription to these challenges. The interstate nature of the grid would simply encourage more of those resources to be built elsewhere, depriving the state of investment opportunities while simultaneously doing little to improve either resource adequacy or the prospects of existing native generation resources.
Resource Adequacy in North Dakota
A Policy Primer

Introduction

The nation’s electric grid is undergoing profound changes as the electricity generation resource mix has evolved in recent years. A system that was at one time engineered overwhelmingly around large baseload plants is in transition. The shale revolution has fundamentally altered how natural gas is produced, and this has dramatically shifted the cost profile for gas-fired electric generation resources. In turn, this has placed economic pressure on traditional nongas resources, especially the large dispatchable thermal generation units against which natural gas most directly competes, namely, coal and nuclear generation. At the same time, intermittent renewable resources have become an increasingly large player on the grid. This move toward renewables has been driven by several factors, among them their decreasing cost profile, their use as a hedge against variable-energy-cost resources, favorable federal tax treatment and subsidies, state renewable portfolio mandates, corporate sustainability goals, and transmission policy geared to promote the development of geographically distant renewables. In addition, various environmental regulations, goals, and mandates imposed at the federal and state levels of government continue to shape the generation resource mix decisions of utilities.

As a major electricity-producing and exporting state, North Dakota is not immune to these forces. Rather, it is particularly influenced by them. Utilities operating in North Dakota are members of one of two regional transmission organizations (RTOs) and are thus impacted by interstate electricity markets, regulatory constructs, and public policies that are often outside of the control of decisions made solely within the state. These dynamics are especially impactful in North Dakota given the profile of the state’s electric generation sector. Unlike many states wherein the generators located in that state primarily serve customers in that state, all of North Dakota’s generation facilities are owned and operated by companies that serve customers in several states.¹

These changes in the electric grid, along with recent catastrophic reliability events in Texas and California, have raised the visibility of what is known as resource adequacy. This document serves as a primer for resource adequacy in North Dakota. The goal is to help policy makers, interested citizens, and stakeholders gain a better understanding of the underlying structural, jurisdictional, and regulatory factors that affect resource adequacy in North Dakota. It also offers a series of takeaways for consideration as the state positions itself during the electric industry’s historic changes.

¹ Emblematic of this reality, North Dakota’s largest lignite-fired electric generation facility, Coal Creek Station, directly provides little or no energy or capacity to North Dakota customers, given its ownership structure and the fact that it delivers its product via a direct current (DC) transmission line that interconnects to the alternating current (AC) bulk power system hundreds of miles away at the western edge of the Twin Cities (Minnesota) metro area.
I. The Three Rs of Electricity: Reliability, Resilience, and Resource Adequacy

The following terms are sometimes discussed interchangeably, but subtle but important distinctions exist between reliability, resilience, and resource adequacy:

- **Reliability**: A broad catch-all term for keeping the lights on that encompasses everything from storm damage, to cyber and physical protection of assets, to adequate generation capacity, to vegetation management and animal damage to distribution wires.

- **Resilience**: The ability for the grid and the resources connected to it to take a hit, be it a natural disturbance or otherwise, and either withstand it or recover quickly from it.

- **Resource Adequacy**: The ability to deliver electricity to customers given a variety of system operating conditions, including in-peak demand conditions. Resource adequacy includes everything from ensuring availability of generation capacity to electricity transfer capability to move power from where it is produced to where it is needed at any given moment.

This document is focused on resource adequacy. Grid hardening, adequate protection from geomagnetic disturbances, and restoration of power after storm or animal damage are all important facets of keeping the lights on, but these topics are beyond the scope of this document. Rather, this document explores the intersection between resource adequacy and issues like industry structure and regulation and public policies in the context of North Dakota, its laws, and its generation resource base.

II. Who’s on First? Defining the Federal/State Jurisdictional Prerogatives

To better understand the policy levers available to North Dakota in relation to resource adequacy, this section provides a brief outline of who does what in the electricity regulatory space.

At first glance, the Federal Power Act’s (FPA’s) division of authority between state and federal government seems straightforward enough. The federal government’s jurisdiction, as it relates to matters explored in this document, is over rates charged for wholesale sales of electricity and the transmission of electricity used in interstate commerce. State authority is over retail sales of electricity. State authority also extends to numerous other matters such as the siting and permitting of infrastructure like generation and transmission.² Put another way, the federal government, via the Federal Energy Regulatory Commission (FERC), has responsibility to ensure that rates are just and reasonable when the sale of the electricity is not for an end use customer or when utilizing the interstate bulk power grid. States, on the other hand, have ostensibly even broader authority over a range of utility operations, including resource portfolio decisions up to and including direct oversight over the utility–end use customer relationship.

In practice—especially as it relates to ensuring resource adequacy—the lines between federal and state authority are blurry and have only been getting blurrier in recent years. FERC, emboldened by the federal courts, has asserted greater jurisdiction over portions of the electric grid that prior

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² There are circumstances in which the federal government may site electric transmission lines, even over the objection of state and local officials, and that federal authority was significantly expanded in the recently enacted Infrastructure Investment and Jobs Act.
generations of regulators would have found legally questionable.\textsuperscript{3} It has become somewhat cliché in the electricity policy world to note that resource adequacy is a state responsibility, but that statement undervalues the enormous impact the federal government has on resource adequacy. While there is a grain of truth to the statement (after all, the FPA does not specifically claim resource adequacy as the exclusive domain of the federal government), it is hard not to think the nature of resource adequacy is more akin to an area of shared jurisdiction. As detailed in the following section, especially in regions with RTOs, forces well beyond any single state’s decision-making affect matters related to resource adequacy and, by definition, those are activities overseen by FERC, not the states.

III. FERC, the States, and RTOs: A Brief History of Restructuring and Where North Dakota Fits Today

*Understanding the Traditional Regulatory Model*

One of the first realities with which anyone new to the electricity policy space must come to terms is the fact there is no one national business/regulatory structure in the electricity utility industry. Prior to the 1990s, this was not the case. In that bygone era, all states regulated their utilities in a comparable fashion and utilities were organized in a similar way.\textsuperscript{4} Utilities, while connected to and coordinated with a larger regional grid, were vertically integrated monopolies\textsuperscript{5} with responsibility for providing electric service to all customers in a franchised geographic area.

Within this paradigm, state prerogatives (as opposed to federal) were and are at their strongest. Because the provision of electricity in this vertically integrated structure is part of a bundled retail service offering to consumers, given the parameters of the FPA, there is relative clarity over which entities have responsibility for ensuring resource adequacy; it is the utility—primarily regulated by the state—that holds that responsibility. At the same time, the state must provide a responsible legal and regulatory climate to ensure the utility has the financial wherewithal to provide electricity service to ensure the public interest is met.\textsuperscript{6}

In the United States, this basic paradigm is still how utilities are structured and regulated throughout most of the Southeast and the West. In these regions, individual utilities control their own balancing area and design and dispatch their own generation fleet to meet consumer demand. These areas are sometimes referred to as bilateral markets because energy trading that occurs (for example, the purchase and sale of electricity when a utility is either long or short on resources) happens through willing buyers and sellers coming to an agreement. This stands in contrast to organized markets, exemplified by RTOs, in which generation and dispatch decisions are made through a central clearinghouse based on economic merit. Although federal regulations regarding

\textsuperscript{3} Two examples are FERC Orders 841 and 2222, which expand federal jurisdiction into the distribution portion of the grid, a space previously considered the domain of state jurisdiction.

\textsuperscript{4} This statement refers to the vertically integrated nature of the traditional monopoly utility while noting the distinctions between the three utility ownership models employed in the United States: the investor-owned model, the cooperative model, and the public power model.

\textsuperscript{5} That is to say, they controlled all components of electricity production and delivery: generation, transmission, and distribution.

\textsuperscript{6} In the case of a cooperative or public power utility, typically an entity other than a state regulatory authority fulfills this responsibility (e.g., a cooperative’s elected board of directors or a municipal utility’s elected city leaders).
a myriad of electricity matters still apply in these bilateral market regions,\textsuperscript{7} it is also clear that state policy prerogatives over the utility industry are strongest within this traditional structure and the federal government’s hand is the weakest relative to the other paradigms. The various regions of the country are depicted in the map below (Figure 1).

\textbf{Figure 1: U.S. Electricity Markets and Regions}

\begin{figure}[h]
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\includegraphics[width=\textwidth]{map.png}
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\textbf{The Era of Utility Restructuring}

Beginning in the 1990s, new utility and regulatory structures began taking root in various parts of the country. Regulators and lawmakers explored how to introduce greater competition into the utility industry. Building on seminal works like FERC Order 888, which promoted nondiscriminatory open access to the nation’s interstate electricity grid, certain states began the process of restructuring (alternatively described as deregulation or retail choice) portions of the electricity industry that were under their auspices. North Dakota legislators in the 1990s studied the concept, as did policy makers across the country. The states that fully restructured their utilities were primarily those with the highest electricity costs and/or a significant industrial customer base that felt it could benefit from having a marketplace that allowed the largest users to put their purchasing power to work through direct retail access to wholesale generation. Like nearly every

\begin{itemize}
  \item For example, open access requirements, FERC standards of conduct, market manipulation enforcement, and mandatory/enforceable reliability standards over the bulk power system, to name just a few.
  \item Source: https://www.ferc.gov/electric-power-markets.
\end{itemize}
other low-cost electricity state, North Dakota maintained the vertically integrated, regulated utility model.

By the early 2000s, about a dozen states had enacted full restructuring, defined as a separation of their utilities into wires and generation functions. In this unbundled structure, the distribution utilities—basically the wires companies that deliver electricity directly to consumers at usable voltages—are still state-regulated monopolies, but the electricity sold over them is produced by generators that may or may not be owned by the former vertically integrated utility companies. Figure 2 displays the various components in getting electricity to a consumer. High-voltage transmission—the long-distance wires that connect generators to local distribution networks—is regulated separately, primarily by FERC, because of the statutory construct of the FPA, which assigns economic regulation of the interstate transmission of electricity to the federal government.

Figure 2: An Illustration of the Traditional Delivery of Electricity

Facilitating the sale of electricity to consumers in this fully unbundled paradigm are third-party middlemen retailers that act as buyers of wholesale electricity for delivery to end use retail customers. The electricity these retailers procure is delivered over the monopoly wires distribution network. The theory behind these changes was that by introducing competition to the generation and retail sales portions of the electricity business, consumers would benefit.⁹ In practice, the benefits of full unbundling to customers—especially residential and small commercial—have proven illusory. The states that were high-cost in the 1990s and chose to restructure are still, by

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⁹ Supporters of restructuring also posited that unbundling the utility would shift the risk of bad investment decisions from “captive ratepayers” to utility company shareholders. Such an assumption looks less supportable in the wake of events like the February 2021 Texas blackout where very real safety and financial risks were shouldered by average customers who had to endure the hardships of a market design that did not support resource adequacy nor an affordable supply of energy.
and large, the highest-cost-electricity states today. There is little to suggest average consumers have benefitted. And consumer protection problems endemic to the retail marketer industry have led to several officials calling for an end to residential retail choice programs.

While restructuring itself is beyond the scope of this document, it is important to understand this background because these structural decisions that states have made have an enormous impact on the policy levers that a state holds in attempting to affect resource adequacy.

**The Emergence of RTOs**

Concurrent with the adoption of retail restructuring in portions of the country, in the late 1990s, there was much discussion at the federal and state levels of government regarding new ways to structure the interstate transmission and wholesale generation portions of the utility industry. Several potential reforms were discussed, but the nonprofit RTO emerged as the dominant model of choice.

An RTO is both a regional grid operator (sometimes compared to an air traffic controller of electricity) and a market operator. Among their several functions, RTOs utilize auctions that give rise to prices which, in turn, perform functions related to keeping the lights on. The generating units that are called upon to supply electricity at any given point in time are selected in the order of economic dispatch across a large geographic area. This system is known as security-constrained economic dispatch. In layperson’s terms, the generation that will be called upon to supply customer demand will be from those units that are willing and able to produce electricity at the lowest cost at that very moment, regardless of what company owns the generation, all while respecting the laws of physics that govern operations of the grid.

Although this form of coordinated unit commitment across a geographic footprint need not necessarily take place within an RTO, the RTO model is unique insofar as its members (generation and transmission owners) are part of a large independent organization that controls the grid and makes market design decisions that have an outsized influence on electricity industry outcomes. Rules that set how generators are compensated, which ones run, obligations of load-serving utilities, making decisions about how load-shedding events unfold, and modeling bulk power system reliability across a regional footprint, to name a few, are matters over which RTOs exercise responsibility in ways that have an impact on resource adequacy.

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13 As with so much in the energy world, the details are complicated and involve an auction structure that produces a price (known as locational marginal price, or LMP), that, in theory, produces an economically efficient outcome.
Where Does North Dakota Fit?

Perhaps befitting the region’s pragmatism, North Dakota, like most of its midwestern brethren, forged a distinctly middle-of-the-road path through the restructuring era. Full utility unbundling and retail choice never found fertile soil in a state with low rates and strong reliability, and the negative experiences of states like California and Montana in the early 2000s only reinforced North Dakota policy makers’ reluctance to board the deregulation bandwagon. However, the state and region also walked a different path than either the Southeast or West, the two regions of the country that still maintain the most traditional forms of utility structure and regulation. Instead, what emerged in the Midwest and plains states is what might be called a hybrid model.

Spurred by FERC Order 2000 and industry dynamics over the course of several years, utilities throughout the central United States voluntarily joined one of two organized wholesale markets that evolved over time: the Midcontinent Independent System Operator (MISO) or the Southwest Power Pool (SPP). This decision resulted in the utilities relinquishing functional control of their generation dispatch and transmission facilities to the RTO itself. At the same time, the utilities remain vertically integrated, regulated monopolies that plan their investments to promote adequate electricity service to customers throughout their own geographic service territory. Put another way, North Dakota utilities still own distribution facilities, generation facilities, and transmission infrastructure needed to reliably serve their customers, but they have given day-to-day operational control to the RTO to determine certain matters, such as which units run at any given time, and balancing electricity flows on the bulk power system.

For policy makers new to the world of the utility industry, these structures are critical to understand because the implications are enormous. Nonetheless, this paradigm in which a utility owns generation and transmission and generation assets but does not fully control them can be difficult to conceptualize because it is so unusual compared to other businesses with which the public is more familiar. What is important to understand about the resource adequacy rubric is how resource adequacy is achieved and who has accountability for resource adequacy. This responsibility in large part depends on the regulatory structure under which a state’s utilities operate.

In the hybrid model employed by North Dakota and most of the central United States, resource adequacy is a shared prerogative. While RTOs in this region set the rules for how the bulk power grid is managed, the state-regulated, vertically integrated utilities can still retain, build, and procure needed generation capacity and seek recovery of those necessary costs from their customers outside of the revenue obtained from the market. This structure is substantively different from those states that have fully restructured. In these fully restructured states, resource adequacy is, in theory, to be achieved through the markets by providing adequate price signals to investors to encourage needed generation investment. Because there is no other revenue stream for them to

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14 For the sake of brevity, this document does not detail the timeline of the development of each RTO nor the timeline of the decisions made by individual utilities, their management, or regulators.
15 While noting that utilities can and sometimes do enter into power purchase agreements (PPAs), which can contractually fulfill their energy and capacity needs via generation facilities owned by a third-party power producer.
access, generators in fully restructured markets like Texas, that cannot make adequate financial returns simply shut down, no matter their contributions to resource adequacy.16

Who Is in Charge of the RTOs? It’s Complicated

Given their sizable influence over the electricity industry and the future of the grid, RTO governance is more than an academic matter. RTOs are curious creatures. Because RTOs are in the business of facilitating wholesale sales of electricity, they are regulated by and accountable to FERC as public utilities. The tariffs under which they operate are filed with and approved by FERC, but they are not public utilities in the sense that a casual observer would recognize them.

RTOs are overseen by independent boards of directors. Their rules, tariffs, and procedures are developed by RTO management after an extensive stakeholder process, which includes the input of member utilities, state regulators, and other interested parties. They are membership–stakeholder-driven organizations, yet they serve a quasi-governmental function that facilitates the delivery of the lifeblood of the nation – electricity.

Multistate RTOs may react to acknowledge the laws and policies of the individual states within their footprints, but they do not have a mandate to execute the policy objectives of a single state government. Nonetheless, their rules and tariffs interact with state public policies in ways that influence billions of dollars in investments.

For policy makers, the key takeaway is to understand that RTOs play an important role in the future of the electricity grid. The decisions made by RTOs impact utility operations, state energy policy, resource adequacy, reliability, and, ultimately, customer bills. Constructive engagement for the benefit of a state’s citizens should be a top concern for state officials seeking to maximize the value of RTO membership.

IV. How Utilities in North Dakota Plan for Resource Adequacy

Although RTOs play a critical role in planning and operating the regional electric grid, when it comes to making decisions about owning, operating, retaining, and constructing electric generation resources to meet the needs of customers, in North Dakota (as in most of the Midwest), the local utilities hold those responsibilities that are so central to the provision of resource adequacy. Especially important in understanding this aspect of resource adequacy is grasping the difference between two concepts: capacity and energy. These terms have a distinct meaning in the utility space but may not be fully understood by those outside of it. “Capacity is the maximum output an

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16 This is true in theory, if not always in practice. Many of the states that have fully restructured, have tacitly walked back the model because they have increasingly sought out-of-market ways to fund preferred generation resources. This, of course, has deleterious effects on the functioning of the markets themselves, both degrading their price-setting mechanisms and also putting states at loggerheads with FERC. In essence, the only way to compete in such a market is for a resource to get its own subsidy, a topic one of the authors of this report has written about extensively. See http://wbklaw-com.securec23.ezhostingserver.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.
electricity generator can physically produce, measured in megawatts. Energy is the amount of electricity a generator produces over a specific period of time."\(^{17}\)

When a vertically integrated utility, like those in North Dakota, creates a plan to ensure resource adequacy it is, in a sense, procuring two different types of products: capacity and energy. Each of these products serves a purpose, and different generation resources serve different needs.

Resources like renewables tend to serve energy needs. Because they have zero fuel cost, they will act as a price hedge against higher-variable-cost resources, which can accrue to the benefit of customers. At the same time, these intermittent resources alone do not tend to provide adequate capacity, given their lack of dispatchability. These capacity needs are met by resources that can provide energy on demand. Utilities attempt to ensure that customers are provided energy at a reasonable price while also ensuring needed capacity is available to meet needs throughout various operating conditions. Understanding the interplay between capacity and energy helps explain why, as MISO has noted,\(^{18}\) the amount of energy derived from thermal generation resources may decline in future years, even as natural gas generation installed capacity may increase. Put another way, the system may require an increase in thermal dispatchable capacity, even though those units may be used, on average, less frequently than they are today.

In today’s grid, resources with high capacity factors are almost always fossil- or nuclear-based resources (or hydro in some cases). Utilities run different modeling scenarios using assorted inputs and assumptions to come to a reasonable resource mix that appropriately balances numerous factors in a way that economically provides resource adequacy to its customers. What comes out of that forward-looking exercise is what is known as an integrated resource plan (IRP), which serves as the utility’s preferred road map for securing capacity and energy resources that support resource adequacy. In many states, this IRP serves as the starting point for regulatory decisions regarding utility company prudency and cost recovery.

V. Case Study: The Elephants in the Room – A Tale of Two States

No two events in electricity policy have captured the attention of the public in recent years more than the California and Texas blackouts. That two of our largest and wealthiest states should suffer from the sort of rolling blackouts and chronic electricity shortages more commonly associated with developing countries has been a shocking revelation in a nation that is a world leader in energy and technology. Given the enormity of these events, policy makers nationwide have been asking, “Can it happen here?" The short answer is, “Blackouts can happen anywhere.” Indeed, even several North Dakota utilities endured controlled load sheds at the direction of SPP during the February 2021 cold weather event. But these relatively brief events pale in comparison to the systemic failures that plagued both California and Texas.

In both cases, the heart of the crises was a failure of resource adequacy. The generation resources (or capacity) available on the system were inadequate to supply consumer demand for extended

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periods of time during periods of system stress related to weather. These sorts of blackouts are substantively different than other high-profile blackout events of recent years, such as the 2003 Northeast blackout or the 2011 San Diego blackout. The 2003 and 2011 events, much like outages due to ice storms, wildfires, or hurricanes or, on a smaller scale, animal damage to distribution lines might be better classified as reliability events. But when considering the recent Texas and California blackouts, hot weather in the summer and cold weather in the winter should not be unexpected. They are not cyberattacks, physical attacks, or geomagnetic disturbances. They are simply system operating conditions that should be part of planning parameters. The California and Texas experiences share some commonalities, although they arise from two distinct circumstances in two very different states.

**California**

California’s utility structure is unique among the states, a circumstance that arises from its calamitous experience with utility restructuring. As an early adopter of full utility unbundling, California has a fully functioning RTO (California Independent System Operator [CAISO]), and the state long ago required its utilities to divest themselves of their generation assets. However, in the wake of the western energy crisis of 2000–2001, California put the proverbial brakes on retail choice. The net result is a utility structure unlike any other. Customers receive their energy from a regulated utility, but that utility primarily depends on independent power producers (merchant generators) to provide the energy and capacity needed for resource adequacy. Merchant generators, in turn, depend on revenue derived from two main sources: 1) contracts entered into with the load-serving utilities and approved by the California Public Utilities Commission and 2) revenues the merchant facilities can derive through services provided and procured in the CAISO market.

Unfortunately, because of California’s aggressive public policies to disadvantage dispatchable generation assets, these merchant generators are the very resources that have struggled the most to maintain financial viability. Thus the state has encouraged the shuttering of the facilities that are still needed for resource adequacy at certain hours of the day.

The 2020 California blackouts arose principally from a convergence of these factors. During hot weather, demand for power was greater than expected. During portions of the day when intermittent resources were producing (especially solar), energy supply was plentiful. But as soon as the sun went down, there was a period in which available generation capacity dipped below that which was required to serve demand. There simply were no more dispatchable resources available; they had retired from the market. At the same time, hot temperatures throughout the West resulted in a lack of import capability, resources CAISO and state officials had anticipated would be available for their use.

19 Characterized by cascading outages across the power grid that had a genesis in grid operators being unaware of system conditions linked to power lines sagging into vegetation.
20 Caused by an operator error which shut down a critical transmission path.
22 Or, increasingly, through a community choice aggregator (CCA).
The phenomena that created this confluence of events has been graphically represented in what has been coined the duck curve (Figure 3 below). The curve visually explains the problem California frequently encounters – several hours of relatively high demand that correspond with hours in the day when solar generation rapidly fades, creating a supply–demand imbalance. 23

At the heart of California’s problems is an opaque accountability structure around how resource adequacy is to be assured. The state itself has some culpability, given its bleeding-edge public policy posture regarding the clean energy transition. Its utilities and their regulators share a degree of responsibility too since their capacity procurement authority should have acted as a backstop to procure needed capacity resources. But CAISO (and its regulator, FERC) is also implicated, since it is the wholesale market that should provide the sort of price signals that retain and incent the right sort of capacity needed for resource adequacy. Out of such dispersed accountability flows inevitable finger-pointing when reliability fails.

Figure 3: The California Duck Curve

Texas

Texas, at least that portion contained within its own intrastate electric grid known as the Electric Reliability Council of Texas (ERCOT), is another outlier in the American utility ecosystem. Unlike any other grid in the contiguous United States, Texas is disconnected from surrounding states. As such, the ERCOT grid is primarily jurisdictional to the Public Utility Commission of Texas rather than to FERC. In addition, Texas is the most fully restructured state in the country. Wires companies own no generation, and energy supply is a matter of retail choice. Even its wholesale market is unique. It is the only market in the United States that has no capacity retention

mechanism. If a generator cannot make money in its energy-only market, it simply shuts its doors and pulls the plug.

One sitting FERC commissioner recently stated that an energy-only market like that employed in Texas is an accident waiting to happen. Because generators are only paid when they are called on to run, the market fails to attract or retain generators that are needed for capacity purposes. These resources simply leave, or do not enter, the market because they cannot recover their full cost of staying in business. What results is a tight, volatile market that may result in periodic windfalls for certain generators, but reliability suffers since resource adequacy is not properly addressed. Its very design encourages the grid to operate at the edge of scarcity, but this lack of cushion contributed to its demise in February 2021. Resource adequacy, to the degree it is contemplated in the Texas model, is supposed to be assured by a market in which real-time prices are permitted to increase drastically. Until recently, Texas allowed wholesale prices to spike to $9000/megawatt-hour (MWh) to encourage generators to be available during times of system stress.

The problem this past February was that it did not matter how high the prices spiked, there simply was no available generating capacity to be had – a profound failure of the market. In this regard, no resource was immune. Natural gas (especially), but also coal and nuclear, units struggled to meet expectations during cold winter weather. Texas is particularly dependent on natural gas, and as a just-in-time fuel source for generation, the widespread supply disruption in gas deliverability created a cascading set of electric reliability issues. Intermittent renewables generally met expectations, but that was a low bar and of little help, since during these sorts of weather events, grid operators do not expect them to provide the capacity necessary to ensure resource adequacy. In short, the restructured market design failed to provide the planning and financial incentives needed for capacity to be available and perform adequately when encountering cold weather conditions that fell outside normal operating expectations. This failure to retain and attract resilient (and, in the case of Texas, winterized) dispatchable capacity is, in turn, a direct result of a market design that has systematically discouraged investment in resilient, reliable generation.

Longer term, the winter 2021 event points to a serious structural capacity deficit with which Texas will have to come to terms. As shown in Figure 4 below, Texas’s energy market is failing to retain and attract new investment in the type of dispatchable capacity needed to meet peak demand. While intermittent resources are increasing in Texas, new dispatchable capacity is lagging. In a state that continues to see strong demand growth, this situation calls into question the suggestion that the Texas winter blackouts were simply a one-off reliability event rather than a harbinger of future events brought on by a failure to maintain resource adequacy. Figure 4 below illustrates how in future years, peak summer demand in ERCOT is projected to be higher than all available dispatchable generation capacity, which raises questions about resource adequacy during times when high demand coincides with low solar and wind output.

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VI. Understanding North Dakota’s Electricity Profile 2021

Having briefly described some of the jurisdictional and policy drivers that impact resource adequacy, the following sections describe North Dakota’s electric sector as it exists today, and where it may be heading into the future.

The state’s electricity production is driven by its significant lignite power generation resources (seven units with a capacity over 4000 MW\(^{27}\)), largely located in the western portion of the state, and wind resources (exceeding 4200 MW of capacity\(^{27}\)), which are continuing to be developed throughout the state. When the capacity factors of these two energy technologies are taken into account, coal produces approximately twice the electricity as wind today.\(^{28}\) Hydroelectric power produced from the Garrison Dam as well as a small but growing contribution from natural gas round out most of the electricity production.

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Electricity consumption within North Dakota was 14.7 terawatt-hours (TWh) in 2014, which equates to approximately 1680 MW of electricity at any moment, on average, significantly lower than its total electricity production. Additionally, North Dakota’s total electricity consumption, on average, is only approximately 60% of the total coal electricity capacity, even when excluding Coal Creek Station, which sells directly to Minnesota, and Heskett Station, which will be retiring in 2022.

North Dakota’s electricity generation has seen significant growth and transition over the last 20 years. Total electricity generation has grown, with much of that growth coming from wind, starting in 2007 (Figure 6). Coal electricity generation, which accounted for greater than 90% of all North Dakota electricity in 2007, has seen a small but gradual drop in generation. Today, coal generation provides approximately 60% of North Dakota’s electricity, although it should be noted that the decrease in percentage share has, to this point, been more correlated to the increase in wind generation facilities, rather than a precipitous drop in coal generation output. It is also worth emphasizing that while this document details only North Dakota-based generation facilities, in reality, North Dakota electricity customers at any given time receive electricity from an interstate grid powered by other resources such as natural gas, solar, and nuclear. All these other resources have a relatively small profile inside North Dakota proper (compared to coal and wind generation),

but nonetheless, they impact grid and market operations for generators across the region, including inside North Dakota.

**Figure 6: North Dakota Annual Generation by Energy Source**

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**Who Does What? How North Dakotans Receive Their Electricity**

Generation owned by cooperatives (both fossil and renewable) makes up the largest percentage of electricity production in North Dakota. In addition, investor-owned utilities (IOUs) operating in North Dakota own or purchase generation from within the state totaling over 1000 MW.

All of North Dakota’s major electricity providers are members of an RTO. The three North Dakota IOUs are members of MISO. The state’s electric cooperatives (Figure 7), participate in either SPP or MISO, as noted:

- Basin Electric Power Cooperative (wholesale power provider) – SPP
  - Central Power Electric Cooperative (District 3 Basin member) – SPP
  - Upper Missouri Power Cooperative (District 8 Basin member) – SPP
- Minnkota Power Cooperative – MISO
- Great River Energy – MISO

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31 Great River Energy electricity produced in North Dakota is primarily utilized in Minnesota via a high-voltage DC transmission line that terminates near the Twin Cities metropolitan area. Great River Energy is in the process of selling its North Dakota Coal Creek Station to Rainbow Energy Center and the high-voltage DC transmission system to Nexus Line.
Basin Electric Power Cooperative is the bulk wholesale power provider to its member systems in a nine-state region. The members located in North Dakota are Upper Missouri, Central Power, and two direct purchasing distribution cooperatives that aggregate with six additional distribution cooperatives located in South Dakota and Minnesota. All of the generation and transmission cooperatives that serve North Dakota deliver their power through a series of distribution cooperatives that are responsible for delivering electricity to end use customers in their service territories. North Dakota’s IOUs are vertically integrated entities in which generation, transmission, and distribution functions are all maintained within a single corporate structure. The maps in Figures 8 and 9 illustrate the customer base and geographical territories of North Dakota’s distribution cooperatives and also those areas of the state served by North Dakota’s three IOUs.34

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34 It should be noted that these service territories are rough approximations. Within each of these areas are numerous places where cooperative and IOU territories abut and certain facilities are shared.
The significant growth in wind across both MISO and SPP adds a new dynamic to power supply that did not exist 15 years ago. Relative to bygone days when nearly all generation resources were dispatchable,35 the variability of intermittent resources like wind and solar creates complexity for grid engineers as more of these resources are brought on the grid. For example, in the broader MISO region, over the last 3 years, wind resources varied from near zero to greater than 20,000

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35 That is to say, resources that could be called upon on-demand (with the caveat that even dispatchable resources have different attributes – some can be brought on- and off-line quickly, some have slow ramp-up and down rates).
MWh on an hourly basis (Figure 10). As shown in Figure 11, SPP experience is similar. A recent MISO study identified the significant complexity that exists once intermittent resources exceed 30% of electricity on the grid (Figure 12). Over half of the underlying complexity of growing renewable resources lies in resource adequacy (which includes resource adequacy and energy adequacy within the MISO study).

**Figure 10: MISO Net Generation from Wind**

![Net generation from wind for Midcontinent Independent System Operator, Inc. (MISO), hourly - UTC time](source)

**Figure 11: SPP Net Generation from Wind**

![SPP Hourly Wind Generation](source)

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These new dynamics require grid operators and utilities to address two overarching matters: 1) operational imperatives related to resources that come on- and off-line quickly, which changes how other resources on the system must respond to keep power flowing reliably, and 2) longer-term financial implications related to the economic viability of generation capacity needed to ensure resource adequacy.

Two recent reports highlight the increasing importance of addressing these concerns. The first is NERC’s 2021 Long-Term Reliability Assessment, which analyzes reliability issues for the industry to address over the next 10 years. Of note, NERC writes:

“Prioritizing reliability during the grid’s transformation and as governmental policies are developed will support a transition that assures electric reliability in an efficient, effective, and environmentally sensitive manner. However, recognition of the challenges that the system faces during this transition requires action on key matters. Natural gas is the reliability “fuel that keeps the lights on,” and natural gas policy must reflect this reality. Furthermore, an increased focus on coordination between the electric power system and the systems that supply it with natural gas must occur. More transmission is necessary to get renewable power to load centers, but it takes time to build high-voltage transmission, and extraordinary siting challenges can be encountered. The shift to more and more inverter-based resources (IBR) brings unique opportunities but also integration challenges that can and must be addressed to assure continued reliability. This is not an argument against the transition but a recognition that, without a collective focus, system
reliability faces risk that is inconsistent with electric power’s essentiality to the continent’s economy as well as the health and safety of its population.”

Of particular interest to North Dakota, the NERC report specifically highlights the MISO region as one meriting close attention. NERC writes:

“In the Midcontinent Independent System Operator (MISO) area, a reserve margin shortfall previously reported is advancing from 2025 to 2024. MISO could face the retirement and resultant loss of over 13 GW of resource capacity over the 2021–2024 period. At this level of retirements, resource additions must increase beyond current projections to avoid a capacity shortfall in 2024. The retirement of these traditional resources also accelerates the change in resource mix and punctuates the urgency for implementing resource adequacy and energy sufficiency initiatives in the area.”

A second report confirms many of the trends identified in the NERC assessment. MISO’s Regional Resource Assessment, released in November 2021, details how the MISO region’s grid is projected to change over the next 20 years and highlights, among other things, the need to reform current structures to better address the operational changes that are occurring due to the decarbonization of the electricity sector.

Regarding SPP, NERC indicates the SPP region should maintain adequate reserve margin levels throughout the 10-year period. Like all other RTOs, SPP will need to continuously monitor and assess the impacts of changes to the operational characteristics of the grid, especially related to the integration of wind and solar resources, and the importance of winterization of generating facilities and coordinating natural gas supply.

VII. North Dakota’s Energy Future

Future Energy Needs

The future electricity needs of North Dakota are expected to increase significantly as it sees continued development of Bakken resources, enhanced oil recovery (EOR) in both traditional and Bakken fields, and the growth of the electric transportation industry. Over the next 20 years, taking into account baseline growth as well as these three opportunities for North Dakota, it is conceivable that electricity consumption in North Dakota could increase by 100% or more.

North Dakota will require more power generation in the next 20 years, according to Barr Engineering’s report, Power Forecast 21 (PF21), as energy demand is predicted to climb by

approximately 250% due to continued development of the oil and gas industry in western North Dakota. Barr Engineering has created the following two scenarios based on models that include commodity price fluctuations, regulatory changes, technological advancements, and other significant factors: 1) low scenario and 2) consensus scenario.

Over a 20-year projection period, the revised forecast predicts an overall growth rate of around 240% (low scenario) to 260% (consensus scenario) in electricity consumption. Total electric energy consumption is expected to grow between 27,000 and 29,000 gigawatt-hours (GWh) by 2040, as shown in Figure 13. Also included in Figure 13 are the original predictions from the 2019 Power Forecast.

**Figure 13: Projection of Future Electrical Load Growth in North Dakota**

It is expected that 670 to 1000 MW of new generating capacity will be required in the next 20 years to match the oil and gas industry’s increasing consumption rate, especially to meet a consistently high load from Bakken fields. In addition to the growth in exploitation of the Bakken in western North Dakota, it is also highly likely that EOR activities will be included in future North Dakota operations. Utilizing the North Dakota Energy Futures Model to look at carbon capture from North Dakota power plants and using that CO₂ for EOR within the Bakken, we can expect a

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42 Developed by the Energy & Environmental Research Center
growth in average power needs by more than 300 MW over and above the growth needs of developing the Bakken without EOR (baseline). If CO₂ from outside North Dakota was also brought in for Bakken EOR, the growth in power needs would increase even more significantly.

**Figure 14: Electrical Demand Growth with CO₂ Enhanced Oil Recovery Integration**

Electrification of the transportation industry will increase electricity consumption beyond today’s usage as we see more adoption of electric vehicles for both residential and commercial use. Although North Dakota lags behind the majority of the nation in the utilization of electric vehicles, their adoption will increase significantly in the coming years in both North Dakota and the regions the state serves. On a national basis, the adoption of electric vehicles is anticipated to increase electricity consumption by 20% to 38% by 2050.⁴³

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VIII. Putting It All Together

*The Good News … North Dakota Is Not Texas or California*

For those wondering if North Dakota is poised to be the next Texas or California, it is important to emphasize there are stark differences between how North Dakota structures its utilities and how it approaches resource adequacy and the conditions from which the California and Texas energy debacles have sprung:

- Unlike California, North Dakota has not aggressively pursued policies to shut down dispatchable power. Also unlike California, North Dakota utilities still own the majority of their generation resources. So long as state regulators\(^\text{44}\) support the retention of needed capacity, there is a straightforward backstop mechanism to retain and attract the sort of generation capacity that supports resource adequacy.

- Unlike Texas, North Dakota electricity companies are planned, vertically integrated utilities that have mechanisms available to ensure that needed dispatchable capacity is retained and

\(^{44}\) Or a cooperative’s governing body.
available 24/7, even if the markets are not appropriately compensating them for their important resource adequacy/reliability/resilience attributes.

More Good News … North Dakota Is Part of a Big Regional Grid

Many of the original reasons North Dakota’s utilities and regulators agreed to join RTOs still hold true. Among the most persuasive include projected cost savings related to scale. Unlike nearly any other product, electricity must be balanced in real time, supply must always meet demand, and the system cannot long endure shortages without catastrophic results. Thus any individual utility operating alone will have to ensure enough generating capacity to meet its day-to-day demand needs as well as build an operating reserve cushion to accommodate demand fluctuations and supply disruptions. By participating in a regional grid that leverages scale, North Dakota utilities can effectively share the burden of retaining these reserves. The consumer costs that can be avoided by not having smaller individual utilities procure all their own reserves can be substantial. In addition, the least-cost dispatch model employed by RTOs has historically proven beneficial to consumers.45

Larger-utility geographic footprints also can support reliability benefits. In a small footprint, a single weather event or generator outage is more likely to cause a reliability problem for that single utility’s customers, but by marshalling the assets of a wider area, these risks may be minimized. In the event of resource adequacy problems in, for example, North Dakota, the state’s utilities will be assisted by assets throughout the region. Similarly, should a reliability event happen somewhere else on the grid, North Dakota-based resources stand available to maintain system stability. This was the experience of 2021’s Winter Storm Uri, in which North Dakota’s lignite fleet supplied significant help to maintain regional resource adequacy.

Finally, North Dakota’s participation in broader regional structures facilitates market access for the state’s generators. Recall that North Dakota generators produce far more electricity than can be consumed in-state. Lacking easy market access, the significant resources available for export would be put at a competitive disadvantage when attempting to serve customer demand in other states. This issue also reinforces the importance to North Dakota of adequate access to high-voltage transmission. For all its wealth of energy resources, North Dakota’s geographical distance from the nation’s largest load centers is a disadvantage, so issues regarding available and adequate transmission capacity loom large.

The Bad News … North Dakota Is Part of a Big Regional Grid

There are tradeoffs entailed in being part of an RTO. For one, the way that market rules are written may not always align with North Dakota’s policy preferences. For example, North Dakota-based generators may be concerned about rules that they believe undervalue the firm capacity attributes that certain resources bring. Or North Dakota wind-based resources may be frustrated by rules that

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they believe stymie transmission development that hold back the state’s wind energy export capability.

Another concern expressed relates to actions that other states may take regarding their own load-serving utilities within the RTO that may impact North Dakota-based generators. While the concern is understandable, it should be noted that these challenges are not the exclusive province of RTOs. Look no further than Montana and Wyoming, where the public policy actions of other states have had implications for Montana and Wyoming coal plants, even though the region exists outside of an organized RTO market.

It is also true that RTOs are heavily influenced by a federal government that may or may not share North Dakota’s energy goals. No matter how sympathetic to state policy directives RTO management may be, RTOs are unquestionably jurisdictional to FERC, and not to states.46

Being a part of a large RTO means there also may be times when North Dakota’s customers are called upon to help balance the grid for the benefit of customers elsewhere. Here too, Winter Storm Uri is instructive. Although North Dakota’s generation assets were winterized and able to handle the cold snap, generators in the Southern Plains were less so. Even though the SPP region experienced nothing like the catastrophe in Texas, there was rotating load shedding for some North Dakotans, primarily related to the cold weather far to the south.

Finally, as noted elsewhere in this document, the locus of control over resource adequacy and responsibility for it is inevitably more diffuse in the context of the bureaucracy of RTO governance than it is for those regions that do not have the RTO overlay.

IX. Concluding Takeaways

- Integrated resource planning, when appropriately used, is a powerful tool to help achieve resource adequacy while providing important regulatory signals for necessary utility investments.47 Given the likelihood that North Dakota electricity consumption will increase significantly in the next 20 years, this sort of planning will be of critical importance. The planning process is one in which utilities plan for the resource adequacy needs of customers looking into the future using several planning scenarios to arrive at a preferred suite of resources, which is known as the IRP. States handle these IRPs in different ways, with some attaching more formality and legal weight to the processes than others.48 At their best, the processes can help align the interests of customers and utilities in ways that help meet public policy goals. Regulators and customers receive some assurance that the utility’s forward-looking plans are appropriately considering cost and

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46 The list of challenges that RTOs face in the energy transition is significant, and one of the authors of this document has expressed his concern that FERC will need to address these matters directly, especially as it relates to the ability of the RTOs, as constituted, to develop appropriate price signals. The way FERC addresses these issues will greatly impact the RTOs and North Dakota-based resources operating within them.

47 In North Dakota, electric cooperatives do not have state regulatory oversight of these matters, but a well-considered forward-looking plan presented to a cooperative’s member-elected board can serve a similar function.

48 The North Dakota legislature recently enacted statutory provisions to establish IRP requirements for Public Service Commission-regulated utilities (North Dakota Session Law, Ch. 342, or North Dakota Century Code § 49-05-04.4. See also North Dakota Session Law, Ch. 343, or North Dakota Century Code § 49-05-17.)
resource adequacy while guided by state public policies. The utility receives feedback that the large shareholder-funded investments they are making are being done in a way that meets the expectations of regulators, which increases assurance that they will ultimately be able to recover those costs and have an opportunity to earn a reasonable return.

- RTOs and regulators need to proactively ensure that individual utilities and states have not made overly optimistic assumptions about how much capacity/energy will be available from the market during times of system stress. While it is incumbent on utilities to appropriately plan to have the resources needed to keep the lights on, that planning must be informed by what is happening in the broader region. If each individual utility, in planning for its own resource adequacy, assumes that imported capacity/energy will always be available, it is not hard to imagine scenarios where demand cannot be met because too many utilities are attempting to draw from the same market at the same time from a finite set of available generators. This issue is an increasing concern at higher percentages of renewable penetration. This necessitates both appropriate utility-by-utility planning within their footprints and also RTO-wide studies to drive realistic assumptions about available capacity deliverability across and among utilities during different seasons and times of the day.\(^\text{49}\)

- North Dakota must be prepared to expend the resources to successfully engage in RTO stakeholder processes, and before the federal government, understanding that the state itself likely has as much influence on the RTOs as any single utility. RTOs are nothing if not complex organizations in which the levers of influence are often ambiguously used in arcane regulatory filings and stakeholder processes. For the state’s interests to be heard, adequate representation is a prerequisite. One of the more effective ways for North Dakota to participate in these discussions is through the state committees established in both MISO (Organization of MISO States) and SPP (Regional State Committee), both of which afford state regulators and their staffs the opportunity to raise issues of concern to RTO leadership.

- North Dakota’s position sitting astride two different RTOs is unusual and creates some wrinkles not encountered by other states. Many of the aforementioned challenges are heightened by North Dakota’s juxtaposition across two RTOs. Although several other states may include the footprints of more than one RTO, the Swiss cheese-like RTO map in North Dakota introduces a different level of public policy complexity that may be unavoidable.

- Policy makers should fully grasp the effective limits of their jurisdiction given these multistate RTOs, focusing efforts on those matters that are within their sphere of influence:
  - While a state may be within its authority to compel its own retail load-serving public utilities\(^\text{50}\) to operate in a certain way (in terms of IRPs, capacity procurement,

\(^{49}\) An important part of this planning are efforts being undertaken at both SPP and MISO to better account for the capacity individual utilities must retain and procure as a requirement of their membership in the RTOs to ensure they are not inappropriately leaning on the system to serve their own load.

\(^{50}\) Again noting that electric cooperatives, as distinguished from investor owned public utilities, are generally not subject to the jurisdiction of the Public Service Commission.
generation resource mix, etc.) those prerogatives do not extend to how any utility serves customers located in other states.

- Neither does state authority extend to requiring RTOs to operate in a certain manner. They are FERC jurisdictional entities. The state’s influence over RTOs is generally one of soft power, although the ultimate policy hammer a state has is to compel its utilities to leave the RTOs altogether.51

- There may indeed be an upper limit to the amount of intermittent resources that can be brought onto the system using available technologies and factoring in cost (relative to other alternatives). At the same time, the exact amount of intermittent resources that can reasonably be accommodated is a function of several factors. More transmission will accommodate more renewables, as will differing types of generation and/or storage that can provide the ability to accommodate the intermittency. The question with all these matters comes down to one of cost. This is where an IRP process can help utilities and regulators assess whether the decisions made today, using the best available information, appear to be prudent and in the best interests of consumers.

- Given the nature of the grid, the percentage of energy coming from intermittent resources within any specific state has limitations as a meaningful data point as it relates to resource adequacy. While there may be value in siting generation close to load, state borders are essentially meaningless in the context of the bulk power system.

- Investment and retention in generating resources within a state is viewed by most states as a meaningful public policy issue as it relates to economic development. Investment in various resources carries with it associated job, income, opportunity, and tax revenues that affect the quality of life within a state, but this issue is distinct from the physical attributes of the grid or resource adequacy.

- As more intermittent resources are integrated into the grid, reliability will hinge on ensuring that necessary capacity resources perform when called upon. This assurance can be bolstered through multiple strategies, including access to firm/redundant sources of natural gas (including on-site fuel storage), coordination between the gas and electric industries, appropriate maintenance of capacity resources, and appropriate valuation of fuel-secure generation resources, to name a few.

- Attempts to ban certain generation resources in North Dakota via prohibitive siting measures or other approaches to discourage investment in alternative generation resources will ultimately prove ineffectual at protecting more traditional native generation resources. All the state’s generation resources are part of broader regional transmission organizations, and resources built anywhere in the region will have spillover effects on North Dakota resources. While North Dakota may be able to prohibit or encourage a particular type of generation within its borders, what is built elsewhere is not controllable and will impact North Dakota-based resources, just as North Dakota-based resources have an impact on

51 There is a bit of a “Hotel California” reality with RTOs, however. Utilities and states can check in anytime, but their tariff rules can make it financially painful to leave. Nonetheless, states have periodically used the threat of leaving RTOs as an effective tool to encourage FERC to change its course on certain controversial policy decisions.
generators outside the state. North Dakota erecting roadblocks to one type of generation resource, for example, wind or solar, will simply encourage more of it to be built elsewhere. This will deprive the state of these investment opportunities while simultaneously doing little to improve the prospects of existing native generation resources.
**Appendix A – Electricity Generation Units in North Dakota**

### Table A-1. Coal-Fired Power Generation Units (4048 MW total)

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Operating Company</th>
<th>Capacity, MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Creek Station</td>
<td>Great River Energy*</td>
<td>1146</td>
</tr>
<tr>
<td>Antelope Valley Station</td>
<td>Basin Electric Power Cooperative</td>
<td>900</td>
</tr>
<tr>
<td>Milton R. Young Station</td>
<td>Minnkota Power Cooperative</td>
<td>705</td>
</tr>
<tr>
<td>Leland Olds Station</td>
<td>Basin Electric Power Cooperative</td>
<td>666</td>
</tr>
<tr>
<td>Coyote Station</td>
<td>Otter Tail Power Company**</td>
<td>432</td>
</tr>
<tr>
<td>Heskett Station***</td>
<td>Montana–Dakota Utilities Co.</td>
<td>100</td>
</tr>
<tr>
<td>Spiritwood Station</td>
<td>Great River Energy</td>
<td>99</td>
</tr>
</tbody>
</table>

*Rainbow Energy Center is in the process of purchasing Coal Creek Station.

**Coyote Station is co-owned by several utilities. (35% Otter Tail Power (operating agent). 30% Northern Municipal Power Agency. 25% Montana-Dakota Utilities. 10% NorthWestern Energy.)

***Heskett Station is scheduled to be retired in March 2022.

### Table A-2. Natural Gas-Powered Electricity Generation (554.8 MW total)

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Operating Company</th>
<th>Capacity, MW</th>
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</thead>
<tbody>
<tr>
<td>Lonesome Creek Station</td>
<td>Basin Electric Power Cooperative</td>
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<tr>
<td>Pioneer Station</td>
<td>Basin Electric Power Cooperative</td>
<td>241.8</td>
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<tr>
<td>Heskett 3</td>
<td>Montana–Dakota Utilities Co.</td>
<td>88</td>
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### Table A-3. Fuel Oil-Powered Electricity Generation (41.5 MW total)

<table>
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<th>Operating Company</th>
<th>Capacity, MW</th>
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</thead>
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<tr>
<td>Jamestown</td>
<td>Otter Tail Power Company</td>
<td>41.5</td>
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Table A-4. Wind-Powered Electricity Generation (4216.7 MW total)\(^52\)

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Operating Company</th>
<th>Capacity, MW</th>
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</thead>
<tbody>
<tr>
<td>Ashtabula Wind Energy Center I</td>
<td>NextEra Energy</td>
<td>196.5</td>
</tr>
<tr>
<td>Ashtabula Wind Energy Center II</td>
<td>NextEra Energy</td>
<td>169.5</td>
</tr>
<tr>
<td>Ashtabula Wind Energy Center III</td>
<td>NextEra Energy</td>
<td>62.4</td>
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<tr>
<td>Aurora Wind Project</td>
<td>Tradewind Energy</td>
<td>299.4</td>
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<tr>
<td>Baldwin Wind Energy Center</td>
<td>NextEra Energy</td>
<td>102.4</td>
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<tr>
<td>Bison Wind Energy Center 1–4</td>
<td>Minnesota Power</td>
<td>496.6</td>
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<tr>
<td>Border Winds Project</td>
<td>Xcel Energy</td>
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<tr>
<td>Brady Wind I and II Energy Center</td>
<td>NextEra Energy</td>
<td>300</td>
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<tr>
<td>Cedar Hills Wind Farm</td>
<td>Montana–Dakota Utilities Co.</td>
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<td>Courtenay Wind Project</td>
<td>Xcel Energy</td>
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<td>Emmons/Logan</td>
<td>NextEra Energy</td>
<td>216.1</td>
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<td>Foxtail Wind Energy Center</td>
<td>Xcel Energy</td>
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<td>Glen Ullin Energy Center</td>
<td>Allete Clean Energy</td>
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<td>Langdon Wind Energy Center I, II</td>
<td>NextEra Energy</td>
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<td>Lindahl Wind Project</td>
<td>Tradewind Energy</td>
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<td>Merricourt Wind Energy Center</td>
<td>Otter Tail Power Company</td>
<td>150</td>
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<tr>
<td>New Frontier Project</td>
<td>Meadowlark Wind I, LLC</td>
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<td>North Dakota Wind Energy Center</td>
<td>NextEra Energy</td>
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<td>Northern Divide Wind Energy</td>
<td>NextEra Energy</td>
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<td>Oliver Wind Energy Center I, II</td>
<td>NextEra Energy</td>
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<tr>
<td>Oliver Wind III Project</td>
<td>NextEra Energy</td>
<td>99.3</td>
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<tr>
<td>Petersburg Wind Project</td>
<td>Minnkota Power Cooperative</td>
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<tr>
<td>Prairie Winds 1</td>
<td>Basin Electric Power Cooperative</td>
<td>115.5</td>
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<tr>
<td>Rugby Wind Power Project</td>
<td>Iberdrola Renewables</td>
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<td>Sunflower Wind Project</td>
<td>Novatus Energy</td>
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<tr>
<td>Tatanka Wind Farm</td>
<td>Acciona Wind Energy</td>
<td>90</td>
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<tr>
<td>Thunder Spirit Wind</td>
<td>Montana–Dakota Utilities Co.</td>
<td>155.5</td>
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<td>Valley City Wind Project</td>
<td>Minnkota Power Cooperative</td>
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<td>Velva Wind Farm</td>
<td>Acciona Wind Energy</td>
<td>11.9</td>
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<tr>
<td>Wilton Wind Energy Center, I, II</td>
<td>Nexterra Energy</td>
<td>99</td>
</tr>
<tr>
<td>Other (demonstrations and state)</td>
<td>NA</td>
<td>3</td>
</tr>
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</table>

\(^{52}\) This table lists the primary operating company for each of the facilities, but in the interest of brevity does not delineate specific ownership or offtake arrangements with individual companies that, in many instances, serve retail load in North Dakota.
About the authors:

Tony Clark is a Senior Advisor at the firm of Wilkinson Barker Knauer, LLP. He was Commissioner of the Federal Energy Regulatory Commission from 2012 to 2016 and a North Dakota Public Service Commissioner from 2001 to 2012. He served as Labor Commissioner in the Cabinet of Governor Ed Schafer and is a former Member of the North Dakota House of Representatives. He holds undergraduate degrees from North Dakota State University and an MPA degree from the University of North Dakota.

Tom Erickson is the Director for Exploratory Research and Intellectual Property and Technology Commercialization at the Energy & Environmental Research Center (EERC). He previously served as CEO of the EERC. Mr. Erickson was the Program Manager for the development of the North Dakota Energy Future Model focused on assessing the impact of future energy changes on North Dakota. Mr. Erickson holds B.S. and M.S. degrees in Chemical Engineering from the University of North Dakota.

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