2021

COMMITTEE ON NATURAL RESOURCES

NEBRASKA LEGISLATURE

December 30, 2021

LR 136

Interim Study Report

Interim Study Relating to Energy Outages, Needs, and Regional Transmission Organization Membership

ONE HUNDRED-SEVENTH LEGISLATURE

FIRST SESSION

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NATURAL RESOURCES COMMITTEE
DECEMBER 30, 2021

I. EXECUTIVE SUMMARY

During the week of February 14 through 20, 2021, an extreme weather event affected the Midwest, including Nebraska, and stretching from North Dakota to Texas. Nebraska generated sufficient power to meet the state's own needs; however, Nebraska residents and businesses experienced rolling power outages over a three day period February 14-16, 2021. The Nebraska Legislature's Natural Resources Committee initiated an inquiry and hearing on the matter (LR48). The hearing took place March 3 2021,[1] and included testimony from representatives of the major public power providers in Nebraska, as well as from rural providers and the Southwest Power Pool (SPP).

The February 2021 power outages gave rise to questions about the reliability of Nebraska's public power resources, structure, and status of the state's policy of providing reliably adequate energy to ratepayers at a low-cost. It has long been Nebraska policy that its solely publicly-owned utilities provide reliable and low-cost power to the ratepayers of Nebraska.[2] There is an expectation that publicly owned utility providers will invest in, transform, and transmit reliable, low-cost power to ratepayers around the clock. Questions about the reliability of public power during the February 2021 event and going forward remained after the hearing. On May 20, 2021, LR136 was referred to the Natural Resource Committee, directing the Committee to conduct an interim study to more thoroughly examine, understand, and evaluate the causes, impacts, and costs of the February 2021 events, and to include an evaluation of the risks, benefits, and costs of membership in SPP. In the months that followed, SPP and certain of the power districts investigated and issued further reports[3] FERC issued a press release foreshadowing its findings. FERC also inquired into the event and listed six (6) recommendations in its report issued in November 2021.[4]

The primary concerns emerging from the interim study are the ability of an outside party to order power outages for Nebraska rate payers, the factors that precipitated the decision to do so, and the impacts of that decision or future decisions similar in nature.

FINDINGS:

The February 2021 weather event increased demand for electricity which could not be met throughout the SPP footprint, increased the cost and decreased availability of needed natural gas resources, and resulted in congested transmission lines in parts of Oklahoma and Texas. Although Nebraska generated energy sufficient for the state's own needs, some other SPP member-states experienced a lack of sufficient generation resources. Nebraska's

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[1] LR48 (Bostelman), Committee Hearing held March 3, 2021.

[2] Neb. Rev. Stat. §70-1301; §70-1001; Public Power History, Nebraska Power Association, www.nepower.org.

[3] SPP issued a March 2021 report, followed by three (3) reports, including a Comprehensive Review of Southeast Power Pool's Response to the February 2021 Winder Event "A Comprehensive Review-Response," issued in July 2021; NPPD issued the February 2021 Weather Event Review June 3, 2021.

[4] The February 2021 Cold Weather Outages in Texas and the South Central United States. FERC, NERC and Regional Entity Staff Report, November 2021.

base load power plants, including its largest generation coal-fired power plant Gerald Gentleman Station and the state's nuclear powered Cooper Nuclear Station provided a significant percentage of Nebraska's power supply, whereas the power generated by other states, that are more heavily dependent on variable energy systems were more vulnerable to destabilization.

To stabilize the grid, SPP exercised contractual authority granted to it by the public power districts and instructed Nebraska members to implement rolling power outages in certain areas of Nebraska over a 2-3 day period. Additionally, SPP instructed certain member-generators in North Omaha to curtail (back off) on production because of the congested transmission lines south of Omaha, and concerns for larger outages or a grid crash.[5]

Since 2009, Nebraska's largest public power districts have been members of SPP, which is a regional transmission organization (RTO) that agrees to accept responsibility for maintaining a reliable flow of electricity on the regional power grid and managing a wholesale real-time financial market. In exchange, members of SPP give SPP authority to control the dispatchable load of the member and to order Nebraska public power districts to enact blackouts and to shut down Nebraska generation.[6] In February 2021, SPP's membership footprint included 14 states in whole or part. As of the writing of this report, SPP includes a 17 member-state footprint.

The Feb. 2021 event resulted in financial impact to Nebraska residents, communities, businesses, and public power districts in Nebraska. While financial-only participants (FOMP) in the SPP market reportedly profited by about $400 million,[7] it is estimated that overall Nebraska suffered losses of approximately $1 billion as a result of the event. Some public power districts had positive revenues from selling energy into the marketplace, while the SPP-ordered curtail of generation kept Omaha Public Power District from selling all dispatchable generation into the market, resulting in a financial loss to OPPD. OPPD, which was required to curtail generation reported a $10 Million loss, while NPPD and LES reported revenues of $150 million and $35 million, respectively.[8] Some rural public power districts reported the February events exposed them to unforeseen additional costs of $10,858,000 or more.[9] Nebraska and Iowa shared an estimated $190 million additional natural gas costs[10].

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[5] Testimony of Lanny Nickell, October 29, 2021; Tab 8 graph SPP report for LR48 Hearing, March 2021.
[6] SPP defines itself as "a nonprofit corporation mandated by [FERC] to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its members." SPP.org/about-us/ accessed 11.12.2021.
[7] Financial-only Participants (FOMP) – investor-participants who do not own or represent physical assets used to generate, transmit, or distribute energy speculate on pricing differentials profited an estimated $400 Million (SPP responses to pre-hearing question #3 requested by Nebraska Natural Resources Committee).
[8] Testimony from Board Chairs October 29, 2021 hearing.
[9] LR49 (2021) materials. South Sioux City $2.8 Million; Wayne $1.268 Million + potential generation loss of $449,000; Falls City $5 Million; Superior $90 K; Wakefield $1.7 Million. (Email 4.8.21).
[10] Black Hills Corp. Provides Estimated Impact of Recent Cold Weather on its Utilities by State, News Release March 1, 2021.

De-stabilization of the power grid has been a growing concern with the expansion of regional transmission organizations, growing dependence on renewable energy resources, and retirement of generators of more stable resources such as coal-powered and nuclear power plants.[11] In December and January of 2017-18, the Independent System Operator for the New England power grid (ISO-NE), another form of RTO, experienced outages and challenges similar to the mid-west's February 2021 event.[12]

Nuclear power and coal plants provide the most dependable resources in the Southwest Power Pool (SPP) footprint, including during the February 2021 cold weather event.[13] "In Nebraska, renewables, including wind energy, are reducing the amount of generation at coal-fired power plants, but the dispatchable capacity provided by facilities like Gerald Gentleman Station and Sheldon Station is essential to the market."[14] There appears to be insufficient natural gas available to compensate for insufficiency of baseload should reliance on renewable generation continue to grow while current baseload generating facilities continue to be shuttered. A graph produced by E3, illustrates the concerns with SPP's inability to maintain reliability of resource adequacy during the February event had the energy portfolio consisted of only renewables and battery storage. While renewable resources were producing during the event, they were producing at lower levels than normal and are of such a nature, that they were and would be unable to fill any gaps, illustrating the need to maintain a portfolio with firm dispatchable resources.[15]

This study revealed that as the fuel mix decreases in use or availability of stable and reliable energy generating assets like coal, natural gas, oil, and nuclear facilities, and subsidizes less stable resources, like wind and solar, it becomes more and more difficult to ensure that electricity flow will be continually reliable. "Reliability begins by choosing the best generation resource for our system needs."[16] Nebraska's generation mix is diversified,"[17] "Base load resources like coal, nuclear, natural gas, or hydroelectric power can run continuously and can be actively controlled to follow load and meet consumer demand. Variable resources like wind and solar, however, rely on environmental conditions which can be hard to reliably predict."[18]

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[11] U.S. Senate Energy and Natural Resources Committee Hearing, , January 23, 2018; "Powering The Future Ensuring that Federal Policy Fully Supports Electric Reliability, An Energy 20/20 White Paper, U.S. Senator Lisa Murkowski, 113th Congress, February 2014; Nebraska Renewable Energy Exports: Challenges and Opportunities (LB 1115 Study, The Brattle Group, December 12, 2014).

[12] Adam, Rod, Atomic Insights, Performance of the New England power grid during extreme cold Dec. 25-Jan. 8, January 26, 2018; https://atomicinsights.com/performance-new-england-power-grid-extreme-cold-dec-25-jan-8/

[13] Strengthening Energy Reliability and Independence", Gov. Pete Ricketts, Aug. 24, 2021; Testimony of Gordon van Weile, president and CEO of ISO-NE indicating he had been sounding the warnings since 2013.

[14] NPPD's initial response to "Nebraska Public Power's Competitiveness in the Regional Market" (Report 7/2021)

[15] Environmental & Energy Economics, Reliability: Resource Adequacy graph, E3, March 2021.

[16] "Reliable electricity is a cornerstone of public power." NREA, Working for Nebraska, July 26, 2021

[17] "Reliable electricity is a cornerstone of public power." NREA, Working for Nebraska, July 26, 2021

[18] "Reliable electricity is a cornerstone of public power." NREA, Working for Nebraska, July 26, 2021

In light of the February 2021 event, the authority granted to SPP under its membership agreements, the power districts' de-carbonization goals[19], and Nebraska's inability to control other states' reliance on what are considered less reliable baseload generation sources, the study also inquired into the risks and benefits of membership in SPP, whether membership continues to meet the policy goals set for Nebraska's publicly owned utilities to provide reliable power at low cost, and the costs associated with potential membership withdrawal.

There were a number of points for consideration before Nebraska utilities became members of SPP and there are many, in addition to monetary costs that will need to be considered if withdrawal from SPP is considered. Before entering into an agreement with SPP in 2008, LES, NPPD, and OPPD considered membership in either SPP or the Midwest Independent System Operations (MISO) and chose SPP based on lower projected costs, governance structure, wholesale market opportunities to enhance transmission interconnections and wholesale market opportunities to the south. Based upon estimates provided by SPP, the aggregate SPP exit fees for the transmission-owning Nebraska members would be approximately $685.8 million.[20]

In 2016, SPP reported that "more than $240 million in annual fuel cost savings [was] realized due to transmission investments during 2012-2014, Overall benefits expected to exceed $16.6 billion over 40 years."[21] In response to Committee requests for information, SPP reports that Nebraska's withdrawal from SPP would be "unprecedented" and would "fundamentally split SPP in half," and that " even if Nebraska is no longer part of SPP, current Nebraska members have a legal obligation under federal law to provide open access to transmission to surrounding providers. This would mean that the utilities must offer transmission access to others on essentially the same terms it provides transmission service to its own customers."[22] Additional thought would need to be given to availability of alternatives and current policy implications of each.

This report contains information and answers to each of the ten (10) directives of LR136, as well as recommendations. Ultimately, the Natural Resources Committee looked to the study for ways to evaluate and ensure that the February 2021 event will not reoccur, inquiring whether any alternatives and/or mitigation measures might assist in avoiding rolling power outages in Nebraska in the future. Many recommendations emerged from the study.

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[19] OPPD, Pathways to De-carbonization: Energy Portfolio Initial Results, Oct. 27, 2021; American Public Power Association, "Lincoln Electric System board adopts 100% net de-carbonization goal by 2040," November 23, 2020; https://www.publicpower.org/periodical/article/lincoln-electric-system-board-adopts-100-net-decarbonization-goal-2040

[20] SPP LR136 response at p.2, noting "these estimates do not represent all of the costs associated with exiting SPP and pursuing an alternative." September 30, 2021.

[21] Transmission upgrades delivering substantial value for Southwest Power Pool members, January 26, 2016.

[22] SPP LR136 response re SPP exit costs, Attachment 1 September 30, 2021.

Recommendations:

1. An RTO such as the SPP is an organization that is set to manage transmission and does not direct generation requirements for its members. It is incumbent upon Nebraska generators to maintain and/or develop generation and related transmission resources in Nebraska that are able to serve Nebraska loads regardless of RTO restrictions and load shedding needs to maintain reliability. Generation strategy must also ensure a diversity of resources that do not rely on limited fuel sources that may be required to be used as a hearing or other energy source.

2. Incumbent generators in Nebraska, especially SPP members, must develop a reliable communication strategy with their wholesale and retail customers so that all consumers receive advance notice when power outages are required as part of any RTO (SPP) process to manage the transmission system or as outages are required for in-state planned outages.

3. As a means to ensure that the available generation resources may be used to serve Nebraska peak loads, it is suggested that an investigation as to the need to split the SPP RTO with sections (such as a northern and southern) that may more appropriately manage grid stability especially as intermittent resources continue to be added to the SPP portfolio.

4. Require the Power Review Board to review and approve all new generation in the state and large scale power purchase agreements to ensure dispatchable in-state generation is available to meet the Nebraska demands during peak usage periods.

5. Require an annual review of the risks and benefits of membership in the SPP and any other RTO to ensure that continued membership is in the best interest of Nebraska consumers.

6. Encourage the SPP or any RTO serving Nebraska to develop a voluntary generation planning subcommittee to address the need for diversified generation to address points and vulnerabilities and reduce the need for RTO directed outages to manage the transmission system.

7. Ensure that SPP completes the 22 recommendations in its Comprehensive Review as soon as possible to address the many failures in the February 2020 event.

8. To address the demand for carbon reduction and non-carbon emitting generation resources, Nebraska utilities should conduct a feasibility study regarding the development of advance nuclear, zero carbon, base-load generation to ensure the needs of Nebraska consumers are met.

9. In an energy only market, in order to maintain an adequate, reliable and cost efficient source of electric generation, SPP or any RTO must appropriately compensate and/or incentivize utilities to maintain and operate dispatchable baseload generation.

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ONE HUNDRED SEVENTH LEGISLATURE

FIRST SESSION

LEGISLATIVE RESOLUTION 136

Introduced by Brewer, 43; Clements, 2; Erdman, 47; Gragert, 40; Halloran, 33.

PURPOSE: The purpose of this interim study is to examine, understand, and evaluate the causes, impacts, and costs of rolling electrical power outages during the extreme weather events of February 2021. The study shall also identify and evaluate the differing effects, if any, of public power district membership in the Southwest Power Pool (SPP) and the costs and benefits of SPP membership.

The study shall include, but not be limited to, an examination of:

(1) The February 2021 rolling power outages to clearly determine the cause, the impact on generation resources, and the necessity to curtail power usage in Nebraska as a result of the event;

(2) The financial impact of rolling power outages on communities, businesses, and residents in Nebraska;

(3) The governing structures, business models, revenue structures and generation diversity of power entities in Nebraska and regional transmission organizations that are available to Nebraska entities;

(4) How transparency, visibility, and public input processes can be improved in SPP decisionmaking and what role Nebraska's rural electrical systems and public power districts play when emergency decisions to shut off electricity are made;

(5) To what degree each public power district and associated regional transmission organizations rely on accredited capacity in Nebraska and by out-of-state members, and to what degree, if any, those accredited capacity sources played a part in the rolling power outages of February 2021;

(6) The effect, if any, changes made by Laws 2016, LB824, had on power generation in the state;

(7) The costs, benefits, risks, and disadvantages of public power

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participation in regional transmission organizations;

(8) The authority of public power districts within the state of Nebraska to join and enter into agreements with regional transmission organizations such as SPP;

(9) Any weather-induced generation reduction from the extreme cold of February 2021 and what impact it had on energy resources; and

(10) Any alternatives and mitigation measures to avoid rolling power outages in Nebraska in the future, including requirements to develop robust baseload capacity in the regional marketplace and the degree to which it may be helpful to develop micro-grids using advanced nuclear reactor technology in Nebraska.

NOW, THEREFORE, BE IT RESOLVED BY THE MEMBERS OF THE ONE HUNDRED SEVENTH LEGISLATURE OF NEBRASKA, FIRST SESSION:

1. That the Natural Resources Committee of the Legislature shall be designated to conduct an interim study to carry out the purposes of this resolution.

2. That the committee shall upon the conclusion of its study make a report of its findings, together with its recommendations, to the Legislative Council or Legislature.

A. INTERIM STUDY PLAN:

Continuing from the hearing and direction of LR48, Legal Counsel for the Committee further researched those items not requiring live testimony, and reviewed newly received materials, consulted professional resources, applicable statute, case law, and other relevant resources.

Advisory contacts were made throughout the study.

Advisory Contacts included: The three (3) major public power districts in Nebraska (LES, NPPD, OPPD), with representatives of the Southwest Power Pool, including Nebraska's representative on that Board. Contact was also made with a representative of Black Hills Energy, MEAN, NREA, and other professional resources.

Questions were developed based upon information gathered and gaps identified when comparing to Resolution Directives. Potential testifiers for the hearing were identified and hearing date on LR136 was set for 1:00 p.m. October 29, 2021.

In the months between hearing on LR48 and LR136, SPP issued three reports based upon their own investigation. The Comprehensive Review of SPP's Response to the Feb. 2021 Winter Storm report, being the most comprehensive of the three, is 108 pages and is the report most cited to and relied upon in the committee's report. The hearing on LR48 included invited testifiers from each of the public power utilities (LES, NPPD, and OPPD) and SPP, as well as representatives of rural utility providers. In preparation for the hearing on LR136, it was decided to invite the chairperson of each governing board from each utility, along with a representative from SPP, Black Hills Energy, and the member of the Nebraska Power Review Board sitting as the Nebraska Representative to the SPP decision-making board.

Sources are cited throughout. Hearing documents and many resource materials are included in the Appendices at the end of this report. Charts from various sources are provided in the report as well. Additional related materials are on file in the office of the Natural Resources Committee.

B. THE HISTORY

- Public power districts in Nebraska are governed by a policy to provide the citizens of the state with adequate electric service at as low overall cost as possible, with sound business practices.[23]
- "Public power districts are required by law to fix rates which are fair, reasonable, and nondiscriminatory." [24]

[23] Neb. Rev. Stat. §1001

[24] Neb. Rev. Stat. §§70-655(1) and 70-1302; Neb. Pub. Power Dist. V. Neb. Pub. Power Dist., 300 Neb. 237 (2018).

- The Power Review Board was established by Legislature in 1963[25].
- The Court recognized authority granted Power Review Board.[26]
- **In 2000**, the Legislature passed legislation requiring the Power Review Board to file an annual report with the Governor, the Legislature and the Natural Resources concerning conditions that may indicate that retail competition in the electric industry would benefit Nebraska's citizens and what steps, if any, should be taken to prepare for retail competition in Nebraska's electricity market.[27] The annual report was to inform the state on five criterion:
  (1) Whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region which includes Nebraska.
  (2) Whether or not a viable wholesale electricity market exists in a region which includes Nebraska
  (3) To what extent retail rates have been unbundled in Nebraska[28] [Added 2000, Laws 2000, LB901, §7]
  (4) Compare Nebraska's wholesale electricity prices to the prices in the region; and
  (5) Any other information the board believes to be beneficial to the Governor, the Legislature, and Nebraska's citizens, such as comparing Nebraska's activities as compared with federal deregulation and retail competition in the region.

Annual reports were filed for years 2000 through 2010.[29]

- **In 2008**, NPPD entered into 20-year power purchase agreements (PPAs) with four (4) industrial wind facilities, agreeing to purchase all power generated by the facilities for the twenty (20) years.[30]
- **In 2009**, The Nebraska Public Power Review Board gave approval for LES, NPPD, and OPPD to become members of the Southwest Power Pool (SPP), a Regional Transmission Organization (RTO).

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[25] Neb. Rev. Stat. §1003, Laws 1963, c. 397, §3, p.1260.

[26] Omaha Public Power Dist. V. Nebraska Public Power Project, 196 Neb. 477 ((1976),("This court cannot interfere with a decision of the Power Review Board (within its limited jurisdiction) unless there is no evidence to sustain the action of the board or, for some other reason, the record shows the action of the board is arbitrary and unreasonable.")

[27] Neb. Rev. Stat. §1003 (7); Laws 2000 LB901, §8.

[28] "Unbundled retail rates means the separation of utility bills into the individual prices components for which an electric supplier charges its retail customers, including, but not limited to, the separate charges for the generation, transmission, and distribution of electricity. §1001.01(8)

[29] In 2010, LB901 was passed, making the annual report/inquiry discretionary.

[30] Laredo Ridge **Wind**, LLC v. Neb. Pub. Power Dist., 11 F.4th 645 (2021).
Laredo Ridge Wind, LLC v. Neb. Pub. Power Dist., 11 F.4th 645, 648, 2021 U.S. App. LEXIS 25286, *1, 70 Bankr. Ct. Dec. 157

- **In 2010,** the Legislature passed legislation making LB901 annual reports discretionary rather than mandatory.[31]
- **In 2016**, the Legislature passed LB824, which de-regulated the market for renewable energy resources to enable and encourage private investment into resources such as wind, solar, biomass, landfill gasses, etc. According to the American Wind Energy Association (AWEA), at the time Nebraska got 8% of its electricity from wind, and in 2019, wind energy provided 19.9% of all in-state production.[32]
- **In 2017-18 (Dec. 25, 2017 to Jan. 8, 2018)**, the New England power grid (ISO-NE) experienced an Arctic Outbreak with substantially below normal temperatures. A briefing took place before the Senate Energy and Commerce Committee. The briefing included statements about the fuel mix used to supply power demand and other challenges, noting 1) Both oil and coal use was significantly higher than normal; 2) Gas and oil fuel price inversion led to oil being in economic merit and base loaded; and 3) as gas became uneconomic, the entire season's oil supply rapidly depleted. (Graph of Daily generation by fuel type)[33]
- **In February 2021**, an extreme weather event resulted in power outages to certain areas over a 2-3 day period. As a result of that event and the outages, a hearing was held on LR48 and representatives from rural and urban electricity suppliers testified before the Natural Resources Committee. A final comprehensive report from the Southwest Power Pool (SPP) was received in late July, 2021.
- **In May, 2021, LR136** was introduced in the Legislature and referred to the Natural Resources Committee during the final weeks of the Legislative Session. As part of the Interim Study for LR136, questions arose about the rewards and risks associated with public power membership in SPP.

C. NEBRASKA'S STATED POLICIES/GOALS OF PUBLIC POWER

Chapter 70 of Nebraska code provides guidelines and requirements surrounding the stated policies for public power in Nebraska, found in Section 70-1001:

1. **To provide adequate, electrical service at low cost.**[34] "Nebraska's public policy is to provide adequate electrical service at as low overall cost as possible, consistent with sound business practices."[35] In addition to local control, the common purposes of public power are to provide reliable, affordable, safe, not-for-profit electricity.

[31] Neb. Rev. Stat. §70-1003(6); Laws 2010, LB797
[32] Wind Energy in Nebraska, American Wind Energy Association (AWEA)
[33] Adams, R. , Performance of the New England power grid during extreme cold Dec. 25-Jan 8, Jan. 26, 2018, accessed online July 30, 2021 (also discussing nuclear facility "retirement" and shutdown.www.atomicinsights.com
[34] Neb. Rev. Stat. §70-1001
[35] Neb. Rev. Stat. §70-1301.

Revenues are reinvested back into the utilities, as well as into community programs, scholarships and other local projects. Public power energizes local economies by providing jobs, lowering the tax burden and supporting policies that safeguard the environment. (OPPD website)

2. **Avoid and eliminate conflict and competition**[36] "In order to provide the citizens of the state with adequate electric service at as low overall cost as possible, consistent with sound business practices, it is the policy of the state to avoid and eliminate conflict and competition between public power districts . . . in furnishing electric energy to retail and wholesale customers, to avoid and eliminate the duplication of facilities and resources which result therefrom, and to facilitate the settlement of rate disputes between suppliers of electricity."

3. **Prepare for evolving retail completion**[37]"it is also the policy of the state to prepare for an evolving retail electricity market if certain conditions are met which indicate that retail competition is in the best interest of the citizens of the state." The state must evaluate the costs and benefits of a competitive retail market based on its own unique conditions. Consequently, there is a need for the state to monitor whether the conditions necessary for its citizens to benefit from retail competition exist."

4. **To encourage private development of renewable** energy sources[38] for sale at wholesale under a statutory framework which protects the ratepayers of consumer-owned utility systems operating in the state from subsidizing the costs of such export facilities through their rates."

[36] Neb. Rev. Stat. §70-1001
[37] Added in 2000 by LB901 §6
[38] Added in 2010 by LB1048 §2

STUDY DIRECTIVES

Directive 1: Examine the February 2021 rolling power outages to clearly determine the cause, the impact on generation resources, and the necessity to curtail power usage in Nebraska as a result of the event.

Nebraska, along with other central states experienced an extreme cold weather event during the week of February 14-20, 2021. Although Nebraska public power generated energy sufficient to supply the needs of Nebraska ratepayers, during the week of Feb. 14-20, 2021, Nebraskans experienced power outages during this time, prompting this study
Electrical power is supplied to Nebraska consumers by public power districts. The three largest producers in the state are Omaha Public Power District (OPPD), Nebraska Public Power District (NPPD) and Lincoln Electric System (LES). NPPD, OPPD, and LES joined the Southwest Power Pool (SPP) in 2009. SPP is a regional transmission organization (RTO) established pursuant to Federal Energy Regulatory Commission (FERC) Order No. 2000 and regulated by the same.

RTOs were established to "balance" the grid, socialize costs of infrastructure buildouts, and to provide access to power in a non-discriminatory manner[39]. At the same time, "Federal and state energy policy trends towards increased renewables".[40] There are special tax incentives that have been offered by the federal government to promote the growth of renewables such as wind energy.[41] As is the nature of other commodity markets, SPP "takes the cheapest fuel available."[42] This allows wind energy to often be the "cheapest" fuel available and even "price in" negatively and still 'settle" at a higher rate than some traditional resources offered to "price in".

SPP's members transfer operational control (but not ownership) of their facilities to the RTOs. In exchange, the RTOs are granted the ability to direct generation or re-dispatch of load from one member for the benefit of another member or for the grid as a whole.[43] RTOs operate in deregulated electricity markets.[44]

Once a member of the RTO, member-generators sell their energy into the RTO and purchase power to service the ratepayers. Members are obligated and "must" "follow

[39] FERC Order 2000, p.5, 95, 202.
[40] SPP 2021 Operating Plan, p. 10, July 13, 2020.
[41] American Power, It's Time to End Subsidies for Renewable Energy, April 17, 2020.
[42] Colloquy between Mr. Nickell and Senator Hughes, Hearing Oct. 29, 2021, p. 13
[43] Performance of the New England power grid during extreme cold.
[44] Glossary Regional Transmission Organization (RTO), Practical Law Glossary Item 6-517-6449 accessed online July 7, 2021.

the instructions of SPP in its role" to re-dispatch generation within the SPP footprint and/or effectuate curtailment of load.[45]

During the week of February 14-20, 2021, Nebraska's public power providers were ordered by SPP to implement rolling power outages to "shed load" of Nebraska ratepayers. Additionally, Omaha Public Power District (OPPD) was required by SPP to curtail, or cutback, on production in parts of North Omaha.[46]

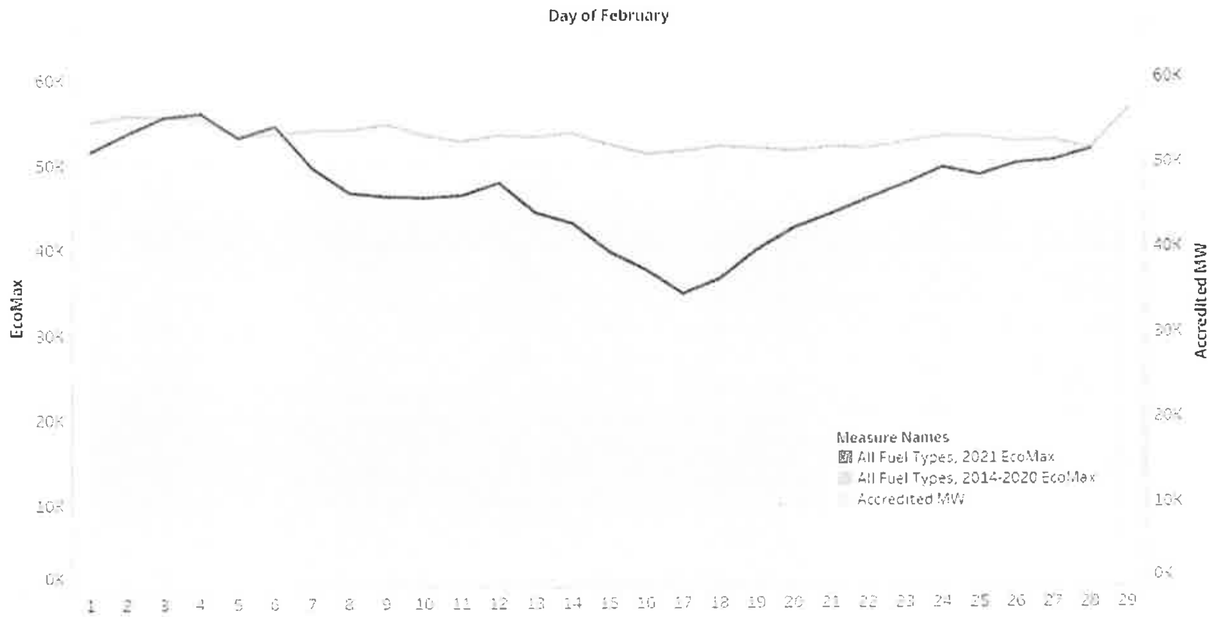
The Nebraska Natural Resources Committee held an initial hearing to explore the causes of the rolling outages just two (2) weeks after the event (LR48). Representatives from each of the largest public power districts (suppliers) in Nebraska, and from some rural area providers and from SPP, were invited to testify at the March 3, 2021 hearing on LR48, The entities also provided additional information as requested by members of the Committee. The materials related to that hearing are available in the office of Legal Counsel of the Natural Resources Committee. Questions remained after the initial hearing, and LR136 was filed requesting a deeper inquiry and was referred to the Natural Resource Committee for study prior to the end of the 2021 Legislative Session.

CAUSE

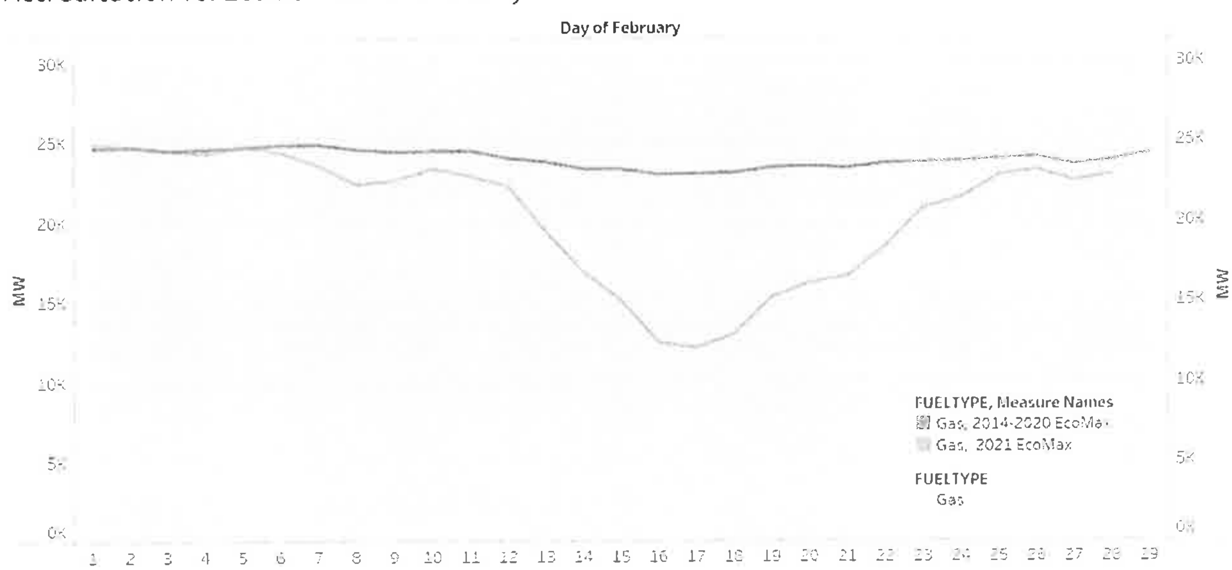
All testifiers agreed that during the "polar vortex" in February of 2021, Nebraska generated sufficient energy to take care of Nebraska's needs but that the extreme cold, unavailability of natural gas fuel, and transmission line congestion in other parts of the SPP footprint caused the need for rolling outages and curtailment in Nebraska.[47] The report from FERC and NERC pointed to freezing of generator components and fuel issues as the top two causes of outages.[48] According to SPP, fuel-supply issues caused nearly 47% of the outages affecting over 13,000 MW of gas generation."[49] High natural gas prices caused rapid spikes in SPP's market prices, and wind generation was highly variable. At pages 51-53 of its report, SPP provided the graphs found below to compare historical versus Feb. 2021 generation.

[45] SPP Membership Agreement, sec. 3.1 Redispatch and Curtailment,
[46] Tab 8 graph contained in SPP/OPPD report for LR48 Public Hearing, March 2021.
[47] Testimony of Lanny Nickell, COO SPP, p. 2-3; According to its own report to its board on Feb.19, 2021, LES experienced three interruption and outage events in 2020: June 4-5; July 9, and October 11.
[48] FERC, NERC Staff Review 2021 Winter Freeze, Recommend Standards Improvements. September 23, 2021.
[49] "A Comprehensive Review- Response", SPP, July 19, 2021, pp.8-9. SPP is "tasked with ensuring the reliable delivery of electricity to a 14-state region"[49] under its agreement with each. From its review, SPP expressed that the polar vortex weather pattern during that time resulted in unavailability of fuels to generate electricity and in transmission congestion in the southern region.

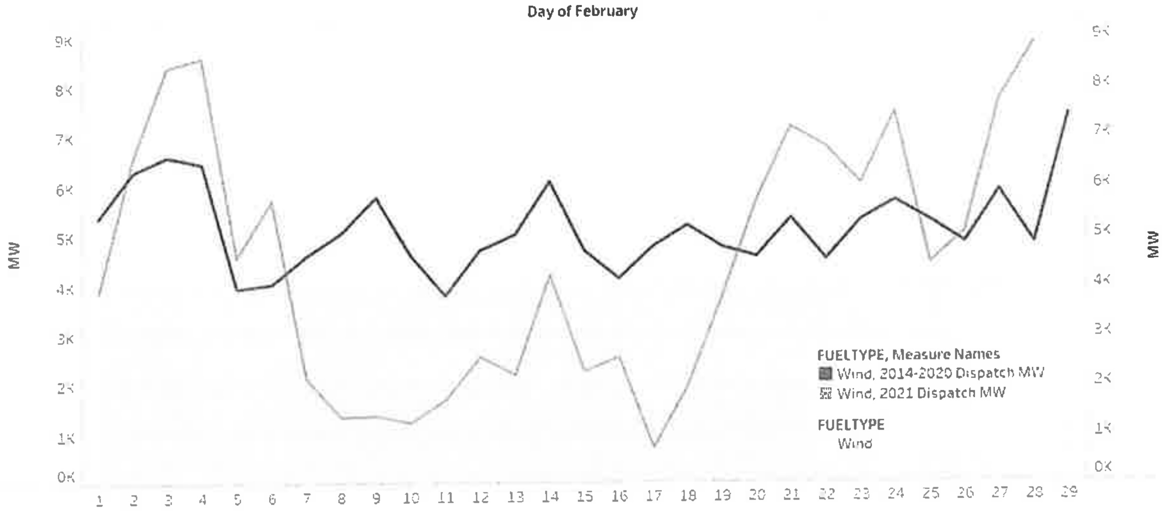
All Fuel Types - **February**



Accreditation vs. Ecomax - Gas - February



Accreditation vs. Dispacth MW- Wind - February



SPP noted that the event "highlighted weaknesses of the components of the supply side of the grid" and "the need to further assess SPP's ability to reliably operate the system with the increased use of intermittent resources and further reduction of base-load resources."[50] "As the resource mix has changed and is expected to continue to evolve, the way resource adequacy has been determined in the past does not appear adequate to meet the needs of the future."[51] Along with other fuel sources, wind was producing less energy than normal. Unlike traditional baseload resources by its nature, wind energy is uncontrollable and thus incapable of being subjected to a "performance-based" accreditation to allow it to be "ramped up" to fill any gaps.

SPP members, including LES, OPPD, and NPPD, are contractually bound to act as soon as practicable on SPP calls to shed load and/or to curtail generation for an energy emergency alert.[52] An energy emergency alert is declared when all available resources have been committed to meet required operating reserves. Beginning on Feb. 4, 2021, SPP issued several weather alerts, "conservative operations declarations" and emergency energy alerts in anticipation of severe cold weather. [53] Usually a net exporter of energy, SPP relied significantly on imported energy, to serve load during the event. Nebraska remained positive in generation for customer needs throughout the entire event. A list of baseload units operational during the event are listed, by the large producers at "Tab 8" in the Appendix at the end of this report.[54]

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[50] "A Comprehensive Review - Response" SPP, July 19, 2021, p.51.

[51] Id. at p. 52.

[52] Testimony of Kevin Wailes, CEO of LES, P at March 3, 2021 Committee Hearing, p. 40-41

[53] A Comprehensive Review of SPP Communications during the Feb. 2021 Winter Storm; Analysis and Recommendations, pg. 78. July 2021; Minutes of LES Admin. Board & Appendices, Feb. 19, 2021

[54] Tab 8, Capacity Factors Market Resources. Provided by SPP, OPPD, NPPD, LES report provided to Committee prior to hearing on LR48, March 2, 2021,

Similar to SPP and its members, MISO is an RTO that exercises functional control over member resources in its footprint.[55] Unlike SPP, "MISO's operators performed well under extremely stressful conditions . . . [and] maintained the stability of the system and avoided the more severe reliability outcomes that occurred in neighboring [SPP] markets."[56]

SPP reports that the rolling blackouts, were caused by "the unavailability of generation, driven mostly by lack of fuel" in the face of increased demand caused by the polar vortex, and quickly accelerating prices and the sudden spike in SPP's market prices.[57] Graphs included in the SPP report are provided within this section. The lack of sufficient natural gas resources were subject to up to 49 time's typical natural gas prices.[58] SPP explains that it "experienced the most operationally challenging week in its 80-year history during Feb. 14-20, 2021.[59] According to SPP, the polar vortex weather pattern during that time caused increased energy usage and resulted in unavailability of fuels to generate electricity and in transmission congestion in several states, including Texas, Oklahoma, and Kansas.[60]

As the transmission lines continued to experience congestion and increased usage exceeded supplies for other members in the SPP market during the relevant times, SPP issued directions for its members in Nebraska to "shed load", and in some areas of North Omaha, to pull back (curtail) on generation.[61] These actions were needed reportedly because "There were other places in the SPP footprint that did not have enough resources and [SPP was] helping support them."[62] 'In effect, what happened was in order for SPP to maintain the operating reserves they needed to keep the system stable . . . they had to basically have a reduction of load because there weren't sufficient resources in the entire footprint."[63]

<u>**IMPACT ON GENERATION RESOURCES**</u>:

Capacity became insufficient during the winter storm and the accompanying strain on available resources as reported in the SPP graphs below. Even beyond the larger power generators, like NPPD, OPPD, and LES, and larger communities of Omaha, Lincoln, and Grand Island, smaller communities were also impacted by the electricity limitations, including the communities of Giltner, Stockham, east of Doniphan, Aurora 1-80 area, Craig, Tekamah-Burt County Public Power District, David City-Butler Public Power District and Doniphan. Columbus and Cedar Rapids, in the Cornhusker Public Power District (customer of NPPD) and South and east Beatrice (NPPD), Elkhorn-Elkhorn Rural Public Power Norris Public Power, Platte Center, Duncan, and Lindsay-Loup Power

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55 https://en.wikipedia.org/wiki/Midcontinent_Independent_System_Operator
56 The February Arctic Event February 14-18, 2021, MISO
57 "A Comprehensive Review-Response", SPP, July 19, 2021, p.8.
58 Testimony at Oct. 29, 2021 hearing.
59 Testimony at Oct. 29, 2021 hearing.
59 Executive Summary, "A Comprehensive Review- Response", SPP, July 19, 2021, p.6.
60 "A Comprehensive Review-Response", SPP, July 19, 2021, pp.36-48
61 Tab 8, SPP, provided for LR48 Hearing March 2, 2021.
62 Testimony of Kevin Wailes, CEO of LES, SPP at March 3, 2021 Committee Hearing, p. 40-41
63 Testimony of Kevin Wailes, CEO of LES, SPP at March 3, 2021 Committee Hearing, p. 40.

District all experienced rolling blackouts on Monday and Tuesday, February 15 and 16 expected to last 30 to 40 minutes at a time.[64]
When SPP's transmission operators in Nebraska shed load (interruption of electricity usage) and curtailed generation (interruption of generation), there were ratepayers at various times and in varied locations who experienced power outages lasting from 30 to 45 minutes or more repeatedly throughout the week.[65] There was at least one farmer/rancher who reported losing livestock to the cold when disrupted electricity caused heat lamps directed at recently born animals were unable to run.[66]

In its Comprehensive Review-Response report, SPP states that "early preparation, timely decisions, and effective communication helped minimize the winter storm's impact on reliability." SPP also reports that its stakeholders indicated general satisfaction with SPP's emergency communications, information sharing, and credibility related to the winter storm response, although some areas of improvement were identified, particularly in relation to end-use customer awareness. In the LES report, the area affected was largely Lincoln/Lancaster County, including Waverly.

As part of its Comprehensive Review-Response, SPP also provided graphs depicting the insufficiency of available capacity. Those graphs for Feb. 15 and Feb. 16, 2021 are provided at pages 35-37 of the SPP report and are included on the following page.

MONDAY, FEB. 15: IN-DEPTH REVIEW.[67] On Feb. 15, available capacity became insufficient to meet system demand.

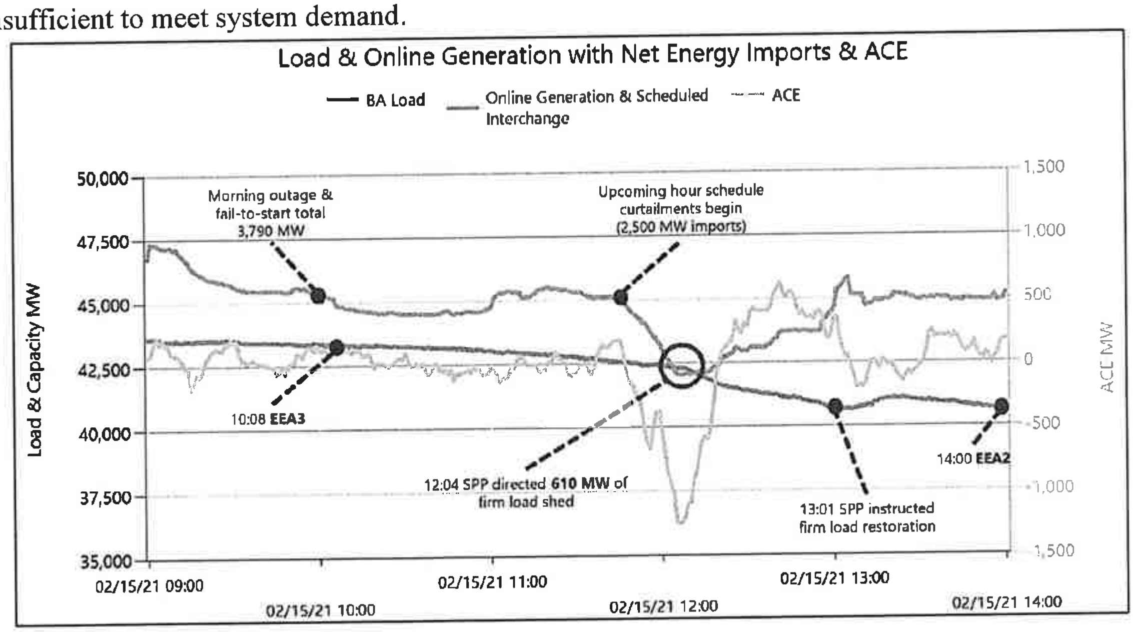


Figure 10: Load & Capacity with Area Control Error (ACE) (Feb. 15, 2021)

64 "Nebraska Unplugged: Power outages sweep across the state.", ABC channel 8, February 17, 2021
65 "A Comprehensive Review-Response", SPP, July 19, 2021, pg. 78; Minutes of LES Admin. Board & Appendices, Feb. 19, 2021
66 Senator Brewer, October 29, 2021 Hearing on LR136.
67 SPP Comprehensive Review-Response p. 35-37

TUESDAY, FEB. 16: IN-DEPTH REVIEW

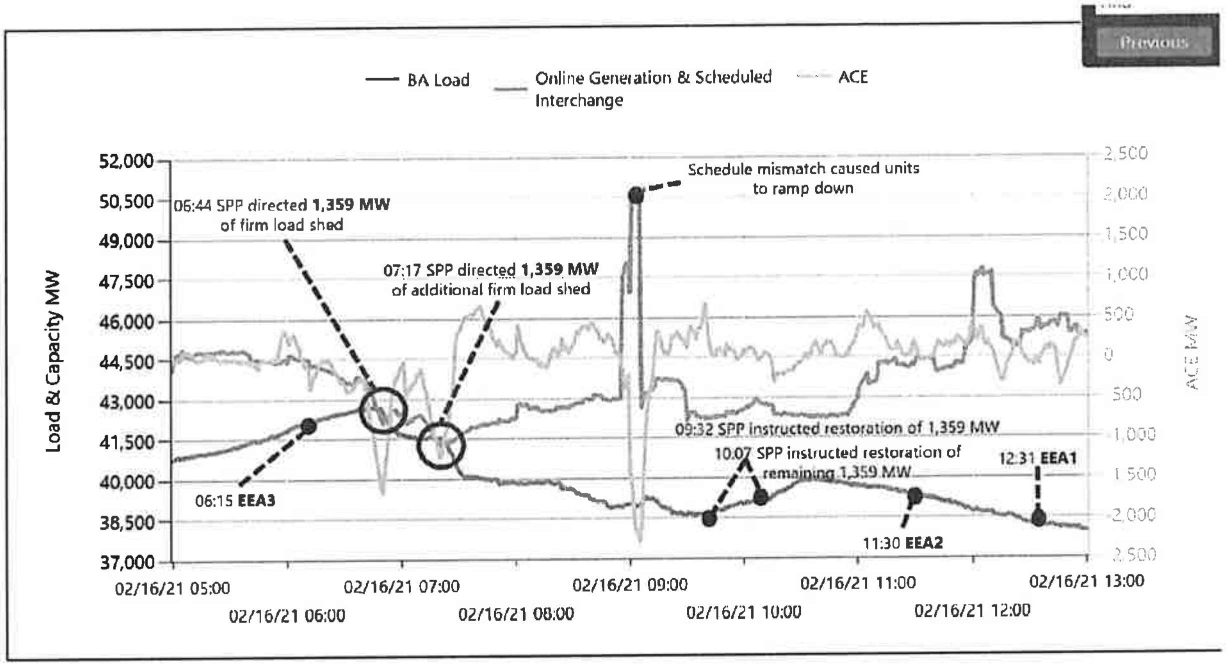


Figure 12: Load & Capacity with ACE (Feb. 16, 2021)

NECESSITY TO SHED LOAD & CURTAIL GENERATION:

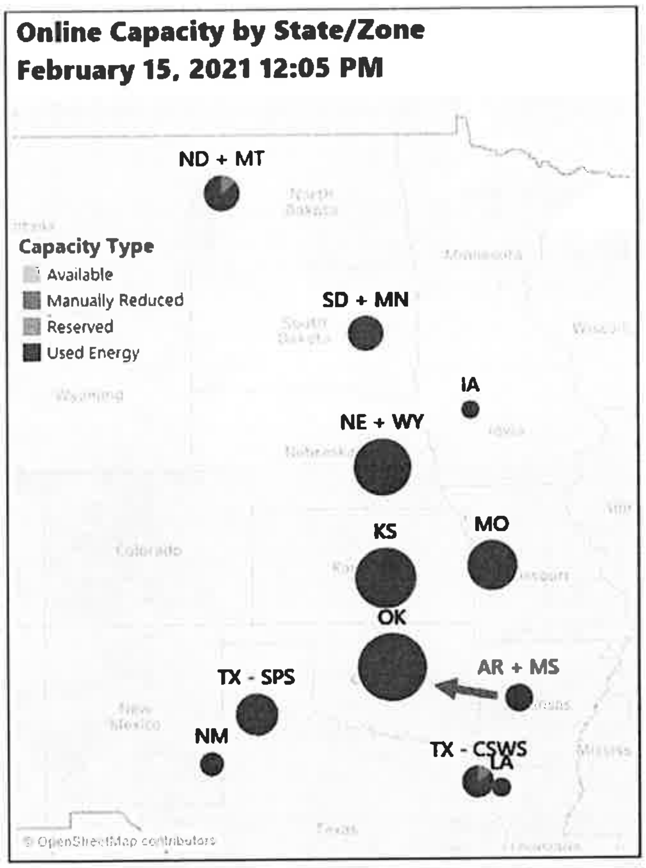
The stated necessity to shed load and curtail generation in Nebraska was reportedly to meet the needs of other of SPP members and to protect the larger grid. SPP's Comprehensive Review reflects the following:

(1) Relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the event.
(2) The SPP transmission system was highly congested at times during the event with limitations that prevented full use of generation available in certain locations. Necessitated use offload-shed procedures and raised questions about the appropriateness of regionally allocating load-shed responsibilities.
(3) Early preparation, timely decisions, and effective communication helped minimize the winter storm's impact on reliability.

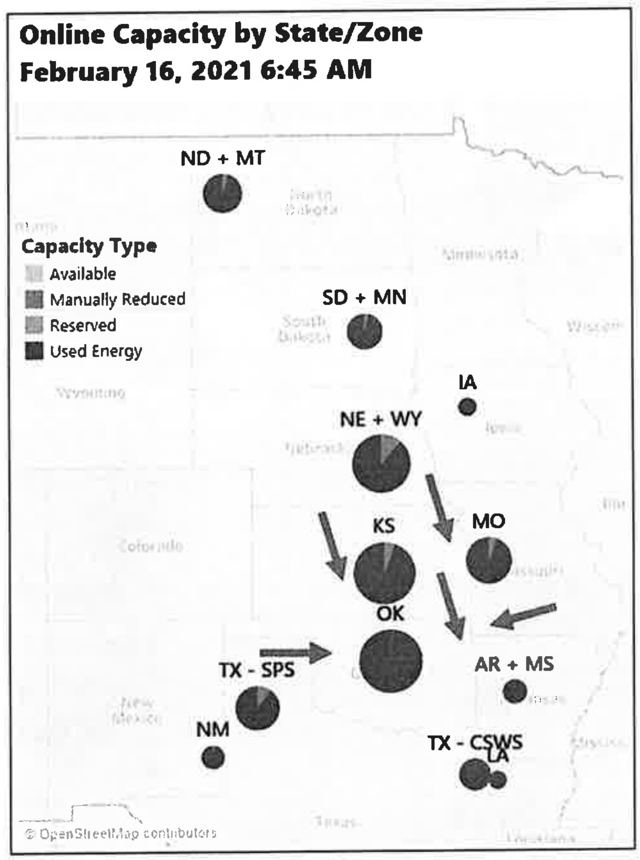
SPP explains that as the transmission lines continued to experience congestion, and usage exceeded supplies for other members in the SPP market during the relevant times , SPP issued directions for its members in Nebraska to "shed load", and some to pull back (curtail) generation. These actions were needed reportedly because "There were other places in the SPP footprint that did not have enough resources and [SPP was] helping support them."[68] 'In effect, what happened was in order for SPP to maintain the operating reserves they needed to keep the system stable . . ., they had to basically have a reduction of load because there weren't sufficient resources in the entire footprint."[69]

SPP further states that the situation also caused congestion at points where SPP ordered certain generators to curtail their power generation. SPP members are contractually obligated to implement SPP orders. SPP reports that heavy usage and continued grid congestion, combined with the other factors mention, necessitated use of load-shed and concurrent curtailment procedures.[70]

The following graphs, found at pages 36 and 38 of the SPP Comprehensive Review-Response, illustrate the issues surrounding moving power within the SPP footprint.



Comprehensive Review Figure 11, p. 36
Map of online capacity Feb. 15, 2021



Comprehensive Review Figure 13, p. 38
Map of online capacity Feb. 16 2021

[68] Testimony of Kevin Wailes, CEO of LES, March 3, 2021 Committee Hearing, p. 40-41
[69] Testimony of Kevin Wailes, CEO of LES, March 3, 2021 Committee Hearing, p. 40.
[70] "A Comprehensive Review-Response", SPP, July 19, 2021, pp.8-9.

SPP RECOMMENDATIONS MADE IN COMPREHENSIVE REVIEW:

SPP issued 22 recommendations ranked in one of three (3) tiers, from "necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks" under Tier 1 to "recommended actions, policies or assessments that would improve SPP's response, communications and public perception during extreme system events, but not urgent"(Tier 3)[71]

SPP reports "The largest single cause of these forced generation outages was attributed to fuel-supply issues, causing nearly 47% of the outages and affecting over 13,000 MW of gas generation," and "The unavailability of generation, driven mostly by lack of fuel, was the largest contributing factor to the severity of the winter weather event's impacts, which was exacerbated by record wintertime energy consumption and a rapid reduction of energy imports."

The SPP recommendations are rated accordingly, categorized into either "action", "policy" or "assessment" and prioritizing a stated "Need to develop polies that improve fuel assurance and resource adequacy" and "highlights the need to further assess SPP's ability to reliably operate the system with more intermittent and fewer base-load resources." [72]

The tables below are the recommendations from SPP's investigation into the event.[73]

TIER 1 (NECESSARY AND URGENT)

FUEL ASSURANCE (FA)

#	TIER	CATEGORY	RECOMMENDATION
FA 1	1	Policy	Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region.
FA 2	1	Assessment	Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events.

[71] "A Comprehensive Review-Response, SPP, July 19, 2021, p.8.
[72] "A Comprehensive Review –Response", SPP, July 19, 20921, p.8, footnotes 2, 3 ("Up to approximately 59k MW of generating nameplate capacity was unavailable and about 30k MW of generating capacity was unavailable due to forced outages when most needed."
[73] "A Comprehensive Review-Response", SPP, July 19, 2021, pp. 12-14.

RESOURCES PLANNING AND AVAILABILITY (RPA)

RPA 1	1	Assessment	Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix.[8]
RPA 2	1	Policy	Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives[9] that ensure sufficient resources will be available during normal and extreme conditions.

TIER 2:

FUEL ASSURANCE (FA)

FA 3	2	Policy	Develop policies to improve gas-electric coordination that better inform and enable improved emergency response.

RESOURCE PLANNING AND AVAILABILITY (RPA)

ERP 1	2	Assessment	Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations.
ERP 2	2	Action	Implement improvements to load-shed processes to be developed by the Operating Reliability Working Group (ORWG), such as: • Utilize real-time load values when determining load-shed ratio shares. • Train and drill on multiple overlapping load-shed instructions. • Perform a detailed review of models used to determine load-shed ratio shares. • Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event.
ERP 3	2	Policy	Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure.

OPERATOR TOOLS, COMMUNICATION AND PROCESS (OTCP)

OTCP 1	2	Action	Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results. • Develop tool(s) to increase operator awareness of Out of Merit Energy (OOME) instructions. • Enhance and expand the use of R-Comm.[10] • Create a reliability dashboard to improve situational awareness for operators. • Utilize member-maintained distribution lists for communications purposes. • Develop a process to update operations management during extreme conditions.

SEAMS AGREEMENTS (SEAMS)

SEAMS 1	2	Action	Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy.

MARKETING DESIGN (MKT)

MKT 1	2	Policy	Develop and improve policies to ensure price formation and incentives reflect system conditions.
MKT 2	2	Action	Develop and implement market design and market-related enhancements identified by the Market Working Group to improve operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: • Improve the Dispatch Target Adjustment Process. • Enhance the Multiday Reliability Assessment Process.[11]
MKT 3	2	Policy	Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided.

TRANSMISSION PLANNING (TXP)

TXP 1	2	Policy	Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events.

CREDIT AND SETTLEMENTS (CR)

CR 1	2	Assessment	Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in the first quarter of 2022.

COMMUNICATIONS (COMM)

COMM 1	2	Action	Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. • Plans to drill emergency communications procedures with all relevant stakeholders. • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date.
COMM 2	2	Assessment	Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.

TIER 3

TRANSMISSION PLANNING

TXP 2	3	Policy	Develop transmission planning policies that improve input data, assumptions or analysis techniques needed to better account for severe events.

CREDITS AND SETTLEMENTS

CR 2	3	Assessment	Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	3	Action	Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities.

COMMUNICATIONS

COMM 3	3	Action	Form a stakeholder group whose scope would include discussion of matters related to emergency communications.
COMM 4	3	Action	To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability.

FERC and NERC also made inquiry, and pointed to freezing of generator components and fuel issues as the top two causes of the event. In their report, they offered recommendations largely addressing weatherization issues as follow:

FERC, NERC Recommendations[74]

FERC/NERC made nine key recommendations and FERC Chairman Rich Glick cautioned that "There was a similar inquiry after Texas experienced extreme cold weather in 2011, but those recommendations were not acted on." The nine recommendations were:

- Revisions to require generator owners to identify and protect cold weather critical components;
- Build new or retrofit existing units to operate to specific ambient temperatures and weather based on extreme temperature and weather data;
- Take into account effects of wind and precipitation in winterization plans;
- Corrective action plans for generator owners that experience freeze0related outages; and
- Ensure the system operator is aware of the operating limitations in the generating fleet so that they can plan mitigation actions.

Directive 2: Examine the financial impact of rolling power outages on communities, businesses, and residents in Nebraska.

SPP reports that the February cold weather event caused increased energy usage as well as a dramatic price increase in natural gas across SPP's Integrated Marketplace footprint.[75] The combined limited generation and increased usage resulted in a $16.3 billion market settlement for impacted operating days.[76] Seventy-four percent, or $12.13 billion was due to various energy product charge types. Prices were much higher than the typical average

[74] FERC, NERC Staff Review 2021 Winter Freeze, Recommend Standards Improvements, Sept. 23, 2021.
[75] "A Comprehensive Review - Response", SPP, July 19, 2021, pp.8-9.
[76] Id. at p. 72; For more detailed information on settlements and market participant credits, see pp. 72-74

for February.[77] SPP further reported that "Total potential exposure (TPE) calculations for day ahead and real-time energy were ineffective in dealing with the short-term, temporary price spikes. SPP applied for, and was granted a waiver relative to prices exceeding the $1,000 price caps, OPPD was instructed by SPP to curtail generation, despite shortages in other member states.[78]

THE SELL:

NPPD and OPPD generally reported earnings from their "sell" into the SPP market. During the February 2021 event, NPPD reported earnings of $150 million, while OPPD reported a $10 million dollar loss.[79] Despite paying unexpectedly high prices for gas resources, NPPD representative stated the "silver lining" of the Feb. 2021 events was that NPPD generated over $150 million in market revenues during the event, of which it currently plans to distribute 50% back to its wholesale market, and 50% will be used to lower operating costs for NPPD.[80] LES reported net revenues of $35 million dollars. There has not yet been any discussion of use of those funds.[81]

THE SETTLEMENT:

On the other hand, rural public power districts report they were subjected to higher gas prices and intentional outages, as well.[82] Mark Eacret, V.P. Energy Services, Big Rivers Electrical Corp., reported. Big Rivers has estimated additional costs associated with that period-added $1,185,290 to Wakefield's February invoice. SPP repriced the weekend of February 13 and 14 and the Revenue Sufficiency Guarantee Charges were reduced accordingly.[83] Portions of Nebraska seem to benefit most from SPP membership during the summer irrigation season. In SPP's 20-year forecast, it appears that OPPD has a 0.87 cost to benefit ratio, while NPPD has a 1.53 cost to benefit ration and LES has a 2.27 cost to

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77 Testimony of Lanny Nickell, COO, SPP, Hearing on March 2, 2021, p. 76,

78 Testimony of K. Wailes, General Manager, LES, Committee Hearing on LR48, March 2, 2021, p.40; Testimony of T. Burke, Pres. and CEO of OPPD, Committee Hearing on LR48, March 2, 2021, p.115

79 Testimony of Amanda Bogner, Chair, Board of Directors for OPPD at hearing October 29, 2021

80 Testimony of Mary Harding, Chair, NPPD Board of Directors, hearing October 29, 2021

81 Testimony of DaNay Kolkowski, Chair, LES Administrative Board

82 Litchfield email March 24, 2021; Eacret later dated March 16, 2021 "the extreme weather events of February 13 through February 19 and the response of the Southwest Power Pool (SPP) resulted in higher than normal SPP energy prices and market costs."

83 On March, 2, 2021, SPP Board of Directors and Members Committee directed a comprehensive review of SPP's response and its stakeholders' response to the February storm. On March 11, 2021 SPP filed (and received) a joint request with MMU for a limited waiver of three tariff provisions. 1) To extend the deadline from 35 days to 75 days for operating day to submit support to the MMU for actual costs for offers above $1,000/MWh submitted from Feb. 11 through Feb. 20, 2021; 2) to extend the MMU's requirement to review and verify cost submissions from 45 days to 105 days from operating day, and 3) to waive the consecutive settlement statements requirement that would otherwise be applicable to the market participant's ability to dispute the S120 Settlements that include operating days Feb. 11 through 20, 2021.

benefit ratio.[84] So, while OPPD is projected to be below 1.0 cost to benefit ratio, OPPD is paying more to the others in SPP for transmission lines and other ancillary costs.

IMPACT ON RATEPAYERS

Estimates are that the February winter power outage event cost Nebraska overall nearly $1 Billion loss as a result of the power outages. At the same time, NPPD acquired gains of $150 Million, LES of $35 Million, and OPPD experienced a loss of $10 Million. Board members from each of the utilities that were gainers indicated that their boards have future plans to decide how much, if any, of those funds will go back to rate payers. In September, 2021, LES recommended a 2022 budget that included a 1% decrease in rates for LES ratepayers[85] OPPD recommended a 3.2% increase in costs of electric service to industrial and commercial properties.[86]

On February 15, 2021, SPP's market price reached an all-time high of $4,274.96/MWh in the day-ahead market, compared to the average SPP day ahead in 2020, which was $17.69/MWh. The rapid spike in SPP's market prices resulted in an immediate concern about liquidity of market participants and created an exponential increase in short-term credit exposure.[87]

IMPACT ON COMMUNITIES:

- Jim Litchfield, City of Wakefield NE. "Our situation here is our wholesale electric bill. It has increased over one million dollars due to the market reprice we saw in February of this year. Many other Communities are in the same situation, seeing very high wholesale billing from their provider."[88]

- Mark Eacret, V.P. Energy Services, Big Rivers Electrical Corp., "the extreme weather events of February 13 through February 19 and the response of the Southwest Power Pool (SPP) resulted in higher than normal SPP energy prices and market costs. Big Rivers has estimated that the additional costs associated with that period-added $1,185,290 to Wakefield's February invoice. SPP repriced the

[84]SPP Regional Cost Allocation Review (RCAR II), July 11, 2016, p.35.
[85] Les.com News 09.17.21 LES proposes rates decrease for 2022.
[86] KFAB News Radio, November 22, 2021.
[87] On March 11, 2021 SPP filed (and received) a joint request with MMU for a limited waiver of three tariff provisions. 1) To extend the deadline from 35 days to 75 days for operating day to submit support to the MMU for actual costs for offers above $1,000/MWh submitted from Feb. 11 through Feb. 20, 2021; 2) to extend the MMU's requirement to review and verify cost submissions from 45 days to 105 days from operating day; 3) to waive the consecutive settlement statements requirement that would otherwise be applicable to the market participant's ability to dispute the S120 Settlements that include operating days Feb. 11 through 20, 2021.
[88] Litchfield email March 24, 2021

weekend of February 13 and 14 and the Revenue Sufficiency Guarantee Charges were much higher than normal.[89]

- On March, 2, 2021, SPP Board of Directors and Members Committee directed a comprehensive review of SPP's response and its stakeholders' response to the February storm. The review was organized to analyze operational, financial, communications, and other aspects of the events of Feb. 14-20, 2021 and to identify how the organization can learn, adapt and be better prepared for future extreme threats to reliability.[90] Five teams and a steering committee were formed.

- Natural gas markets are not subject to price or offer caps.[91] Extremely high natural gas prices were the primary driver of record-high energy offers that exceeded the FERC-required offer cap.[92]

IMPACT ON FINANCE ONLY PARTICIPANTS

- SPP reported that FOMPs experienced an estimated $400 million gain on virtual transactions during the February event.[93] A full list of current market participants, including FOMPs, can be found on SPP's website: https://www.spp.org/about-us/membersmarket-participants/. SPP's Market Monitoring Unit ("MMU") recommended "a study to assess the effectiveness of virtual transactions during the winter weather event and identify any potential lessons learned or recommendations going forward." The MMU's full report can be found at: https://www.spp.org/documents/64975/spp_mmu_winter_weather_report_2021.pdf.

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[89] Eacret letter dated March 16, 2021 (including SPP explanation to city of Wakefield to reprice for weekend Feb. 13 and Feb. 14 in compliance with FERC Order No. 831, which addresses revising regulations to address incremental energy offer caps (concluding the offer caps in RTOs/ISOs to be unjust and unreasonable). . FERC "require[s] that each regional transmission organization (RTO) and independent system operator (IS):: (1) cap each resource's incremental energy offer at the higher of $1,000/megawatt-hour (MWh) or that resource's verified cost-based incremental energy offer; and (2) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices (LMP)."; Further clarify that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs."

[90] "A Comprehensive Review - Response", SPP, July 19, 2021.

[91] Comprehensive review, p.8, #2

[92] FERC Order No. 831.

[93] SPP responses Eacret Letter to pre-hearing question #3 requested by Nebraska Natural Resources Committee.

Directive 3: The governing structures, business models, revenue structures, and generation diversity of power entities in Nebraska and regional transmission organizations that are available to Nebraska entities.

Nebraska is the only state with entirely public owned power. Each public utility is not for profit and is locally owned by customer ratepayers. All Public Power Districts, except LES, have boards elected by the voters in their respective districts. LES has a board of Directors appointed by the Mayor of Lincoln. Today, Nebraska's public power utilities monitor more than 27,000 miles of power lines, "From small towns to big cities, and all the miles in between, public power is part of our GOOD LIFE in Nebraska!"[94]

Southwest Power Pool (SPP): SPP is a Regional Transmission Organization (RTO) governed by a 10-member board of directors consisting of members of the organization from different states. RTOs first developed in the 1990's to accommodate the Federal Energy Regulatory Commission's (FERC) policy to encourage competitive generation through requiring open access to transmission. SPP exists and operates for the benefit of the bulk electric transmission system and to "ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity." [95] The largest public power utilities in Nebraska entered into membership agreements in 2008 and their membership was authorized by the Nebraska Public Power Board in 2009. SPP's stated function is "to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity.[96]

FERC regulates transmission and wholesale sales of electricity in interstate commerce. SPP is mandated by FERC to ensure customers in the region receive reliable power, adequate transmission infrastructure, and competitively priced electricity. SPP and its members coordinate the flow of electricity across more than 65,000 miles of high-voltage transmission lines spanning now 17 states.

SPP business is directed by an elected Board of Directors, which elects Officers consisting of President and Corporate Secretary, at a minimum. Officers carry out the rights, duties, and obligations of SPP pursuant to the authority granted by the Board of Directors. [97]

Officers and employees must be independent of any Member organization. Technical and administrative staff of SPP are hired by the Officers to accomplish SPP's mission. The Integrated Marketplace launched in 2014. [98] Membership is voluntary and qualifications

[94] Nebraska Power Association, "History", https://www.nepower.org/public-power/history.html accessed 5/11/21

[95] Southwest Power Pool, Inc. Bylaws, Governing Documents Tariff, Generated 3/1/2021, Sec. 2.3 and 3.0, Accessed online on 9.1.2021.

[96] Governance, SPP, online access 8.6.21 spp.org/governance/.

[97] SPP Bylaws No. 3.4.

[98] "Today in Energy", U.S. Energy Information Administration, April 4, 2021.

must be met. Members participate in decision-making through Membership in Organizational or Working Groups, with participants appointed to groups by the Board of Directors.[99]

Members of SPP pay an annual membership fee of $6,000 or other amount established by the Board of Directors along with a monthly assessment of uncollected cost-share of all operating costs, financing costs, debt repayment, and capital expenditures associated with the performance of SPP's function as assigned by the Board. Membership fees are not subject to refund.[100]

State Members of SPP February 2021

• Arkansas	Iowa	Kansas
• Louisiana	Minnesota	Missouri
• Montana	Nebraska	New Mexico
• North Dakota	Oklahoma	South Dakota
• Texas	Wyoming	

- SPP also provides contract reliability coordination services in Arizona, Colorado and Utah.

Lincoln Electric System (LES): LES has an Advisory Board appointed by the Mayor of Lincoln. The Board is responsible for developing and adopting strategic lanes for the utility and for the control and management of the property, personnel, facilities, equipment and finances of LES.[101] They do not receive compensation and may serve a maximum of three three-year terms. Operations are overseen by eight executive team members. The current team consists of members who have served for between 7 and 21 years: the Chief Executive Officer (CEO) is hired by LES Human Resources. The CEO hires the remaining team members, who, in turn, hire their subordinates. The utility is a non-profit with revenue streams from rate-payers in the form of 1) Customer charges, 2) Facility charges, 3) Energy charges, 4) Demand charges, and miscellaneous fees. LES reports #14 lowest bill in the Nation.[102] As a public power utility, LES reports it pays dividends to its customer-owners in the form of lower rates.[103] Retail Rates are approved by the LES Administrative Board and the Lincoln City Council pursuant to Lincoln Municipal Code Chapter 4.24; Non-Retail Pricing is approved by the LES Administrative Board.[104] Residential, non-residential, general service-demand, large power contract and Business Rates. LES Rate

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99 Southwest Power Pool, Inc. Bylaws, Governing Documents Tariff, Generated 3/1/2021. Accessed online on 9.1.2021.

100 SPP Bylaws, section 8.2 through section 8.4. "Legitimate public interest groups (e.g. consumer advocates, environmental groups, or citizen participation groups) may seek a waiver of the annual membership fee. If granted, the waiver will remain in place, subject to an annual review of the group.

101 Testimony of DaNay Kolkowski, chair Administrative Board, hearing on LR136, October 29, 2021.

102 LES reports 2020 Average monthly bill is $97per 1,000 kw; $31,000 per 1,000 kW.

103 "Summary of Retail Electric Rates For 2021" LES website les.com/sites/default/files/rates-summary, accessed August 26, 2021

104 "Rate Schedules 2021" LES website les.com/sites/default/files/rates-schedules-book.pdf, p.3, accessed August 26, 2021.

Schedule 2021 is a 74 page report available online or from Natural Resource Committee upon request.

LES reported anticipating payments of $12.7 million to local governments in 2021 through annual payment in lieu of tax and city dividend for utility ownership[105] and generation assets diversified as follows: Natural gas 35%, Renewables in the form of wind, hydro, solar, and landfill gas 34%, and coal 31%[106] LES reported 49% Renewables equivalent of retail sales in 2020. LES serves Lincoln and the surrounding area.

Nebraska Public Power District (NPPD): NPPD is a non-profit public power utility governed by an 11 member Board of Directors who are elected by the people to six-year terms. The Board is responsible for strategic planning and general oversight of operations. The NPPD "footprint"/Jurisdiction includes all or parts of 86 of Nebraska's 93 counties. NPPD is a member of SPP and a partner with The Energy Authority (TEA).[107] NPPD's generation assets include coal 19.9%, Nuclear 48.6%, Gas & Oil 5.2%, Wind 8.3%, Hydropower 8%, Purchases 9.9%, Solar, misc. .1%[108].

Districts Served by NPPD

• Burt County PPD	Butler PPD	Cedar-Knox PPD
• Cuming County PPD	Custer PPD	Dawson PPD
• Elkhorn RPPD	Howard-Greeley RPPD	KBR RPPD
• Loup PPD	Loup Valleys RPPD	McCook PPD
• Niobrara Valley EMC	Norris PPD	North Central PPD
• Northeast NE PPD	Perennial PPD	Polk County PPD
• Seward County PPD	South Central PPD	Southern PD
• Southwest PPD	Stanton County PPD	Twin Valleys PPD

Omaha Public Power District (OPPD) OPPD is a non-profit public utility, and generation member of SPP with an 8-member Board of Directors, each member elected in their district to serve a six (6) year term. The Board is responsible for oversight of OPPD generating assets, strategic planning and general oversight of operations and a stated commitment that "the OPPD resource planning process will provide the resources and analytical capability to adequately assess OPPD's Integrated Resource Portfolio to ensure reliable, competitive, cost-effective and environmentally sensitive service for our customer owners.[109] OPPD reported its 2015 fuel mix portfolio to be: 63% coal, 13% renewables, 23% nuclear, and 1 % oil and natural gas. Since the 2017 closing of the Ft. Calhoun facility, OPPD no longer includes nuclear energy as part of its portfolio.[110] In 2020, OPPD met 38.4% of retail

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105 "LES to distribute $21.7 million to local governments" LES News, April 26, 2021.

106 Coal-fired plant resources include Laramie River Station om Wyoming, Gerald Gentleman Station in Nebraska, and Walter Scott, Jr. Energy Center Unit 4 in Iowa

107 "The Benefits of Working with the Energy Authority, which manages power, natural gas, portfolios, RTO market and trading; and bilateral energy trading. www3.teainc.org, accessed 8.31.21

108 NPPD Website nppd.com/powering-Nebraska>Energy Resources accessed 8.31.21; Testimony of Mary Hardin, Chair, NPPD Board of Directors, Hearing October 29, 2021.

109 OPPD Resource Planning Update, June 16, 2016, SD-9.

110 OPPD Integrated Resource Plan, Feb. 2017, pp. 22-29

customer electrical energy sales with wind energy, energy from landfill gas, hydro energy, and solar energy.[111]

Districts served by Omaha Public Power District

Serving over 849,000 people in 13 counties:

- Burt
- Cass
- Colfax
- Dodge
- Douglas
- Johnson
- Nemaha
- Otoe
- Pawnee
- Richardson
- Sarpy
- Saunders
- Washington

NREA (Nebraska Rural Electric) Member Systems

- Burt County PPD
- Butler PPD
- Cedar-Knox PPD
- Cherry-Todd Electric Cooperative, Inc.
- Chimney Rock PPD
- Cornhusker PPD
- Cuming County PPD
- Custer PPD

Directive 4: How transparency, visibility, and public input processes can be improved in SPP decision-making and what role Nebraska's rural electrical systems and public power districts play when emergency decisions to shut off electricity are made.

This LR is not the first time questions about transparency surrounding the SPP market have arisen. In 2017, Senator Wayne introduced LB657, to adopt the "Retail Electricity Transparency Act" asking to have access to the wholesale rates paid by the utilities for power they pass on to ratepayers. The bill had a hearing in Natural Resources but did not advance from committee.[112]

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[111] NPA Load and Capacity Report, August 2021.

[112] LB657 was indefinitely postponed at the end of session without being advanced to the floor.

In the current study, the rolling power outages ordered by SPP raised questions about the appropriateness of transferring authority of operations to an RTO with out-of-state headquarters and members.

The role of electric utility suppliers in Nebraska that are members of the SPP footprint, is to immediately act on instructions given by SPP with regard to requesting that consumers lessen their use of power, shedding load, or curtailing load.[113]

Regarding the February 2021 event and the SPP decision-making process:

(1) The balancing of load and supply is made through established programming and algorithms within the SPP systems.[114] SPP is currently reviewing the algorithm that resulted in Nebraska and other SPP member "states and utilities who has excess generation . . . being asked to shed load."

(2) Currently, member input on decision-making matters in SPP is required to be accomplished primarily through Membership participation in Organizational Groups. Member representatives may be appointed to Groups by the Board of SPP.

(3) SPP Board meetings adhere to the Nebraska's Open Meetings Act which requires that any public body that elects to meet must (1) provide reasonable advance publicized notice of its meeting and (2) prepare an agenda of items to be discussed at the meeting.[115] Directors. "Participation in certain sessions of Organizational Group meetings where market sensitivity issues are discussed may be restricted to persons representing entities that have executed Electric Reliability Organization (ERO)'s Confidentiality Agreement. [116]

(4) When an order to "shed load" or "curtail generation" order is given by SPP, members of SPP, like LES, NPPD, and OPPD must do as instructed or be heavily fined in an unspecified amount.[117]

SPP said "early preparation, timely decisions and effective communication and coordination with [its] utilities and neighboring systems helped minimize the winter storm's impact on reliability, and our load shed actions mitigated the risk of uncontrolled cascading blackouts, which would have been much more severe, would have lasted much longer and, and could have impacted a much larger part of our community.[118]

As part of its investigation into the February event, SPP formed a team to review and make recommendations in the area of communications, as well as others. The top 22 recommendations, including those from the communications team are included in the response to Directive 1 in this report, and are explored in-depth in the SPP report A Comprehensive Review of SPP Communications During the February 2021 Winter Storm Analysis and Recommendations (July 7, 2021) (61 pages)

[113] SPP Membership Agreement, section 3.1.

[114] Testimony of Lanny Nickell in response to questions from Sen. Moser, Hearing Oct. 29, 2021, p.36-37.

[115] Testimony of Lanny Nickell, COO SPP, Oct. 29, 2021 Hearing on LR136, p.3

[116] Under jurisdiction of FERC, regulates reliability of the electric power grid, Bylaw section 2.3.

[117] SPP Membership Agreement.

[118] Testimony of Lanny Nickell, COO of SPP

As background, SPP launched its Integrated Market in 2014. "In the Integrated Market (IM), each market participant bids in generation to supply their forecasted load for the following day as required by the SPP".[119] Electricity is a commodity traded in the IM with SPP acting as the market operator, responsible for clearing transactions. As a market operator, SPP determines which power is bought and sold based on current demand (load), supply from generators located throughout the footprint, and price offerings.

Generation mix decisions are made by the utilities, guided by a mixture of reliability and economics. SPP sees its current role as one "to make sure that [they] connect it reliably throughout the appropriate transmission infrastructure." As a result of the February 2021 event, SPP has been "forced to ask . . . should SPP, in addition . . . determine the minimum reliability attributes that have to be present in the generation mix," and "provide ways to incent that to show up?" also asking, "Can we afford to let certain generation that provides the reliability balance we need can we afford to let it retire? Can we afford to let it go away?"[120]

Directive 5: Examine to what degree each public power district and associated regional transmission organization relies on accredited capacity in Nebraska and by out-of-state members, and to what degree, if any, those accredited capacity sources played a part in the rolling power outages of February 2021.

During the February event, SPP "rel [ied] on imported energy to serve as much as 14 percent [about 6,000 MW] of [its] load."[121] During the event, SPP was importing from "several utilities to the east, and was receiving energy from as far away as New Jersey, the east coast."[122]

Accredited capacity means the electrical rating given to generating equipment that meets the Utility's criteria for uniform rating of equipment. During the Feb. 15 and 16th time frame, SPP had 94,648MW of Nameplate Capacity and 62,577MW accredited winter

[119] Goss & Associates Economic Solutions, Nebraska Public Power's Competitiveness in the Regional Energy Market, Produced for Wind is Water Foundation, Dr. Ernie Goss principal investigator, Dec. 12, 2016.

[120] Testimony of Lanny Nickell, COO of SPP, Hearing Oct. 29, 2021, p. 18.

[121] Imported from outside of the SPP footprint. During the event, SPP was importing from "several utilities to the east, and were receiving energy from as far away as New Jersey." Testimony of Lanny Nickell, Oct. 29, 2021 Hearing, p. 3-4.

[122] Testimony of Lanny Nickell, COO, SPP, Oct. 29, 2021 Hearing, p.4

capacity. Some examples of non-dispatchable energy is being built and then sold to markets outside Nebraska.

1. Out-of-state agreements for Nebraska-generated power is reported by the Nebraska Power Association in its Load and Capability Report.[123]

2. WEC Energy Group (an electric generation and distribution and natural gas delivery holding company based in Milwaukee, Wisconsin, has a Purchase and Sale Agreement for 80% of the Upstream Wind Energy Center (202.5 MW nameplate) located just north of Neligh, Nebraska Invenergy (developer) has a 20% interest in the project.
3. J.M. Smucker Co. and Vail Resorts have Power Purchase Agreements to purchase energy from Plum Creek Wind Project in Wayne County, Nebraska (2020)

4. Miligan 1 300 MW industrial wind complex in Saline County went commercial in May 2021, selling generated energy into SPP.

In 2019 SPP reported Energy Production by fuel to be: 34.9% coal; 37.5% wind; 25.9% gas; Nuclear 6.0%; Hydro 5.6%, solar .2% and other at .1%.[124] Comparatively, for 2020-2021 SPP reported winter accredited capacity to be 35.2% coal; 47.9% Natural Gas; 3.1% nuclear, 2.1% Fuel oil; 5.1% hydro, and 16.3% wind.[125]

During 2020, SPP reported 262,730 TWH of energy production made up of 31.3% wind; 30.9% coal, and natural gas, nuclear energy and hydro, solar, and other resources rated at 11.2% combined. Actual name plate capacity for wind during the Feb. 2021 event was 12-16% availability on average.

In its 2021 Load and Capability Report, the Nebraska Power Association forecasts that "based on Existing and Committed resources, a statewide deficit for Minimum Obligations" [126] will occur in 2039. "Over the twenty-year period of 2021 through 2040, the average annual compounded peak demand growth rate for the State is projected at 0.7% per year (individual utilities range from -0.1%/yr. to 1.2%/yr.). The escalation rate that was shown in last year's report for 2020 through 2039 was 0.6%. "Normally, the SPP winter accredited capacity mix is 45% gas fired, 38.5% coal, 5.6% wind, 3% nuclear, and 4.8% hydro. Fuel oil and solar deliver much smaller contributions to the capacity on the regional grid".[127]

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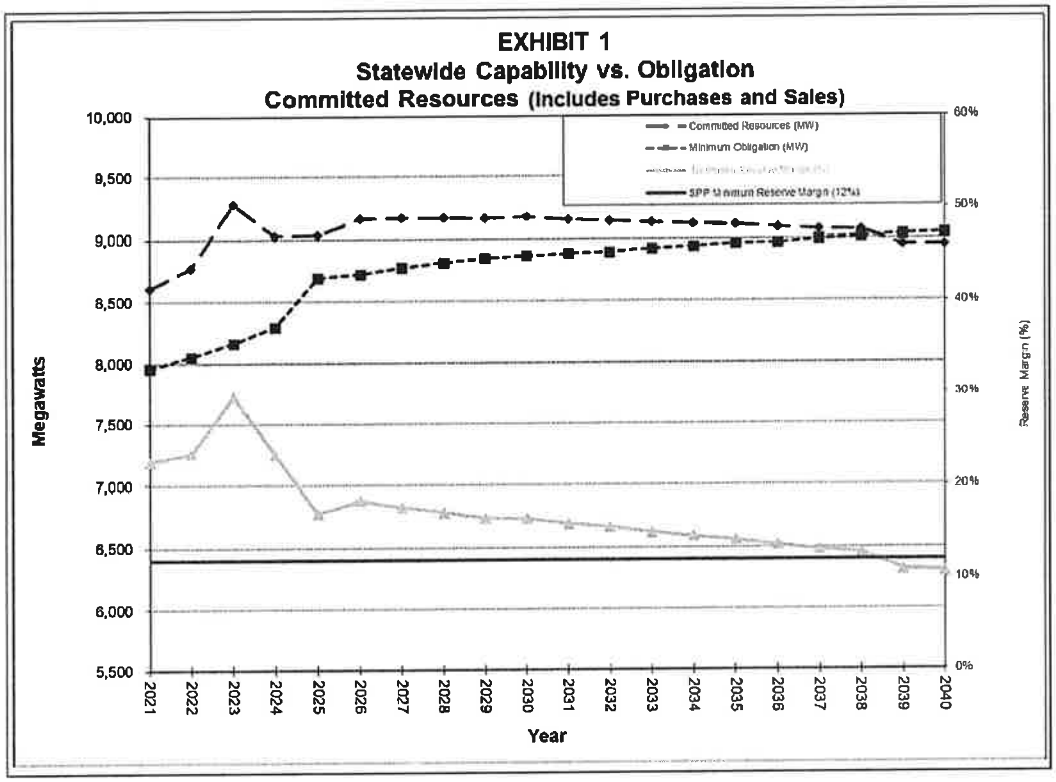
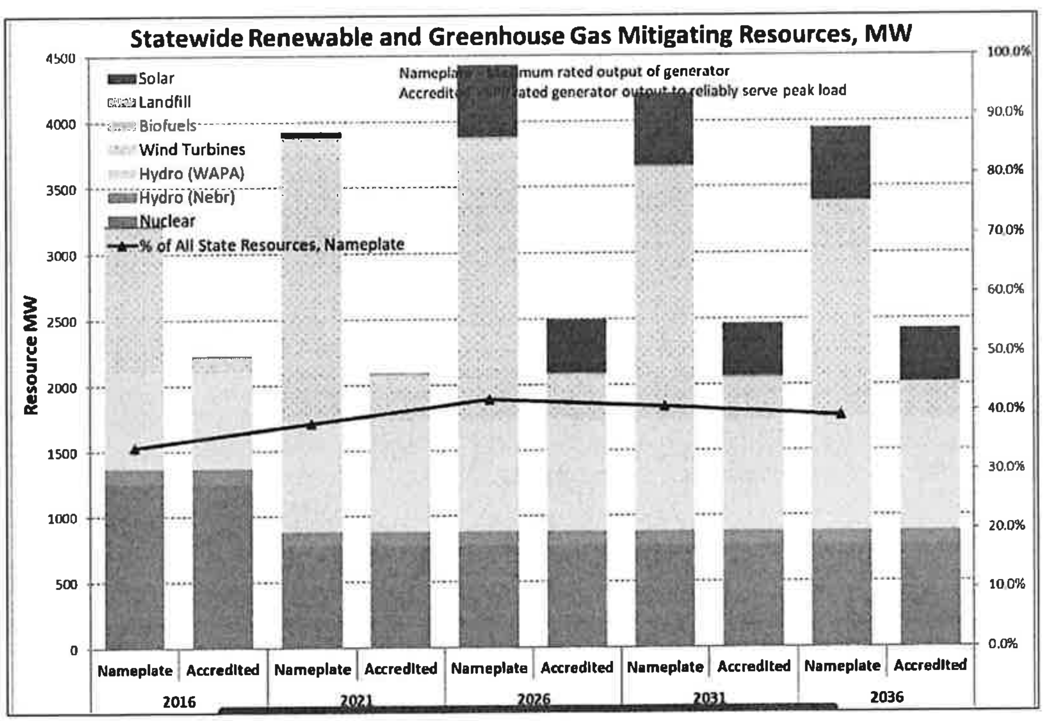
[123] Nebraska Power Association Load and Capability Report, August 2021, p.6.
[124] "February 2021 Winter Storm Event." SPP, March 2021.
[125] "A Comprehensive Review-Response." SPP, July 2021, p.48, Figure 2; "Minimum Obligation" refers to the SPP required statewide reserves of 12% over the normal weather.
[126] Minimum obligation is the SPP Nebraska load requirement and equates to 736 MW in 2021 and 849 MW by 2040. Nebraska Power Association Load and Capability Report, August 2021.
[127] Lanny Nickell. Director of Power Engineering, to Rod Walsh, Director of Power Engineering, Power Grid International Renewal, March 25, 2021.

The graphs from the Nebraska Power Association addressing Statewide Capability vs. Obligations and Statewide Renewable and Greenhouse Gas Mitigation Resources are printed below as part of this study report.





Source: 2021 Load & Capability Report, Exhibits 1 and 7.1

Directive 6: Examine the effect, if any, changes made by Laws 2016, LB824, had on power generation in the state.

In 2016, LB824, now codified in Chapter 70[128], was signed into law. LB824 signaled a policy shift from allowing exports of electric power exclusively by public-owned export facilities to renewables in order to encourage private investment in renewables. The bill removed the prohibition previously set forth in Neb. Rev. Stat. §70-1001, et seq. and removed several requirements in the approval process and did not require Power Review Board oversight for privately-owned renewable energy projects.[129]

LB824, was enacted "to provide a less burdensome regulatory framework designed to facilitate the Export of renewable energy into the Southwest Power Pool (SPP) market,"[130] and to allow private investors to build alternative energy generation systems without the oversight or approval required of public power districts in the state. The privately owned industrial wind complex, for instance, can now be built and power generated, giving the investor(s) profit opportunities that are not afforded to public power districts in Nebraska. The limitation on the private producer is that the investor owned generator cannot provide power or sell power directly to the end user in the retail market but can sell to wholesale suppliers like NPPD, OPPD, and into the SPP marketplace. In the market place, the wind energy receives priority to be picked up quickly because of its low cost once the facility gets past the cost of build out. The investor-generator also receives federal subsidies for every megawatt of energy produced. Consequently, even though available at a lower cost than other fuel sources like coal, the wind energy producer receives more money per MW/hr because of the subsidy paid.

Development and investment in renewables in Nebraska have steadily increased since LB824 was passed by the Legislature. Further development in wind energy is expected to increase. It has no fuel cost and is receiving a tax subsidy for each megawatt hour produced which can exceed the marginal cost of energy.

At the same time, "Wind energy is reducing the amount of generation at coal-fired powered plants, and the dispatchable capacity [currently] provided by Gerald Gentleman Station and Sheldon Station is essential to the market."[131]

The industry recognizes that "The larger the percentage of wind in SPP, the more challenging it becomes to use conventional generators. Dispatchable energy capacity must be available when the wind isn't blowing or can't be controlled. There is a cost to having "back up" generation. "Wind generation alone is not capable of following and serving load

[128] When codified, , LB824 (2016) amended §70-1003, 70-1012, 70-1012.01, 70-1013, 70-1004, 70-1014.01, 70-1014.02, and 70-1015.

[129] Laws 2016, LB824

[130] Testimony of Sen. McCollister at Legislative Hearing at Natural Resources Committee on January 27, 2016, p. 3

[131] NPPD's initial response to "Nebraska Public Power's Competitiveness in the Regional Market"

in the integrated market. All types of generation are needed, including baseload, carbon-free nuclear and reliable coal units."[132]

System capacity is the maximum load that a generating unit or generating station can carry under specified conditions for a given period of time without exceeding approval limits of temperature and stress of electricity resources available to use if needed. [133] There is a recognized difference between the stable availability (dispatchable power) of traditional energy generation and that of renewable resources. The capacity for dispatchable power depends on the internal technical capability of the plant to maintain output for a defined period of time. For non-dispatchable power, particularly renewable energy, nameplate capacity refers to generation under ideal conditions. Output is generally limited by weather conditions, hydroelectric dam water levels, tidal variations and other outside forces. Equipment failures and maintenance usually contribute less to capacity factor reduction that the innate variation of the power source.

E3 initially incorrectly reported that during the Feb. 2021 event, ALL types of renewable resources were impacted.[134] At its seminar where the graph found at p.45 of this report was presented with that information, however, it was clarified that nuclear power resources were NOT impacted. Renewable resources were producing, but at lower levels than normal due to cloud cover and low wind speeds.[135] These periods when little to no energy can be generated with the use of wind and solar power are a big issue in energy infrastructure. A significant amount of electricity is generated by renewables and in such times, to ensure power during these times, alternative energy sources must be present in a sufficient capacity to meet needs. This then requires either overbuild of other renewables or peaking units to address gaps in intermittent renewable generation.

SPP reported wind energy performance had no impact during the February event, but reliance on gas resources did. SPP anticipated 4,000 MW of wind energy were expected during the event, and that "showed up." "2,000 MW of accredited nuclear capacity showed up. At the same time, gas generation produced only 12,000 MW of the 30,000 MW expected. SPP acknowledged that '[t]he largest contribution of energy in the SPP footprint during the event was 17,000 MW from coal." [136]

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[132] NPPD's initial response to "Nebraska Public Power's Competitiveness in the Regional Market"
[133] FERC Glossary of terms, https://www.ferc.gov/industries-data/market-assessments/overview/glossary#C accessed July 2021.
[134] Reliability: Resource Adequacy graph handed out at October 29, 2021 hearing.
[135] The extended low renewable periods are known in the industry as "Dunkelflaute", describing a period of time in which little to no energy can be generated with the use of wind and solar power.
[136] Testimony of L. Nickell, CEO of SPP, Hearing on LR136, Oct. 29, 2021, p.8.

Directive 7: Examine the costs, benefits, risks, and disadvantages of public power participation in regional transmission organizations

In 2008, OPPD, NPPD, and LES signed membership agreements with the Southwest Power Pool (SPP) and thereafter joined SPP with approval from the Nebraska Power Review effective April 1, 2009.[137] One member of the Nebraska Power Review Board sits on SPP's Regional State Committee. In 2016, an extra stipend up to $20,000 per year was authorized for that member of the Power Review Board that represented the Board at the Southwest Power Pool Regional State Committee or its equivalent successor.[138]
The week of Feb. 14-20, 2021, these members were directed by SPP to enact rolling power outages and/or to curtail power generation during a period in which Nebraska was generating enough electricity to meet the needs of the State. The event raised concerns about giving a party outside of Nebraska (SPP) the authority to order Nebraska's citizen-owned public power districts to cut power to Nebraska residents and businesses. It also raised questions about the risks and benefits associated with SPP membership and considerations if there should be consideration of withdrawing from SPP and/or other RTOs.

Benefits

The following represent purported benefits of membership:

(1) Analysis of problems and challenges encountered. After the incidents surrounding the February 2021 winter storm, SPP staff and membership began to gather information, analyze the incident(s) and response, report key observations, and make recommendations for improvement.[139] Five teams were formed to review organizational, financial, communications and other aspects of the event.[140] Identification of members, stakeholders, and the teams they served on is available as part of the description of "The Comprehensive Review Process" found at pgs. 15-28 of the SPP Comprehensive Review in the Appendices of this report.

(2) Integrated Marketplace. Launched by SPP in 2014 – making SPP the first RTO to design, build and implement a Day 2 market on time. It has evolved includes a "Day-Ahead Market with Transmission Congestion Rights, a Reliability Unit Commitment process, a Real-Time Balancing Market replacing the Energy Imbalance System (EIS) Market and the incorporation of price-based Operating Reserve procurement. The

137 Per FERC filing for Amendments to its Bylaws and Membership Agreements September 30, 2008.
138 Neb. Rev. Stat. §70-1003, Laws 2016, LB824 §4
139 A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations, Version 1.0, Southwest Power Pool, Published July 19, 2021
140 "A Comprehensive Review-Response" Southwest Power Pool, Published July 19, 2021, p.6

Integrated Marketplace also consolidated the SPP footprint's 16 legacy Balancing Authorities into an SPP Balancing Authority.[141]

(3) Fill gaps in power if needed. "Belonging to the association is if we have a problem locally, we can get power from somewhere else."[142] The example given by NPPD was service to Nebraska when generation was interrupted by flooding in 2019.[143]

(4) Revenue and savings, though this claim may need further examination. SPP estimates that "Nebraskans have benefitted from the $1 billion dollar savings since the market went live in March 2014 (through 2016 report).[144] At the same time, there is some dispute about whether Nebraskan ratepayers realize the financial benefits claimed. In his 2016 report, Dr. Ernie Goss reported, "Since the implementation of the SPP Integrated Market (IM) in March 2014, electricity prices have trended downward due to the addition of wind generation and lower natural gas prices. Because of the high cost of production at some plants in Nebraska, ratepayers have not fully benefitted from the more than $11 billion saved by lower electricity prices from the SPP IM."[145]

(5) Less generation needed.[146] "A consolidated balance area among NPPD and the other balancing area utilities, there is less generation needed to address the unexpected loss of generation or other supply and demand events that was needed when there were 16 separated balancing areas. Spreading the risks over a large footprint reduces total cost of managing the issues." This statement appears to assume an area without congestion.

(6) Reduction of overall costs/competitive rates. The premise is that the Integrated Market has reduced the overall cost of generation by serving the entire market with the lowest cost fuel based on marginal costs.[147]

(7) Help neighbors in the region. At the October 29, 2021 hearing on LR136, NPPD also noted as a benefit the opportunity to "help [Nebraska's] neighbor" and when Nebraska falls short of generation sufficient to meet its needs.[148]

Financial Considerations:

Infrastructure costs shared: Socialized financing of infrastructure is cited as a benefit for Nebraska utilities. SPP has authority to control the transmission lines and spread costs

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[141]spp.org/markets-operations
[142] Colloquy between Sen. Moser and Lanny Nickell, COO SPP, Hearing Oct. 29, 2021, p.9
[143] Testimony of Amanda Bogner, Chair, OPPD Board of Directors, Hearing Oct. 29, 2021.
[144] NPPD's Initial response to "Nebraska Public Power's Competitiveness in the Regional Market" (Report)
[G]Goss & Associates Economic Solutions, Nebraska Public Power's Competitiveness in the Regional Energy Market, Produced for Wind is Water Foundation, Dr. Ernie Goss principal investigator, Dec. 12, 2016,
[146] NPPD's Initial response to "Nebraska Public Power's Competitiveness in the Regional Market", p.2.
[147] Id. "Spreading the risks over a large footprint reduces total cost of managing the issues,"
[148] Because of "a consolidated balance area among NPPD and the other balancing area utilities there is less generation needed to address the unexpected loss of generation or other supply and demand events that was needed when there were 16 separated balancing areas. Spreading the risks over a large footprint reduces total cost of managing the issues.

among regional members of the organization. SPP also has authority to review members' plans or desires to add lines and, if it approves, can spread the cost for new infrastructure across the entire footprint, which reduces hard costs to Nebraska utility providers.[149]

Fuel Cost Savings/Low cost energy disputed: A primary goal of making all of Nebraska public power, was to provide adequate power at a low cost.

In 2016, SPP reported that overall benefits to membership are expected to exceed $16.6 billion over 40 years."[150]

Whether or not the rates are upholding Nebraska's policy to keep costs for Nebraska ratepayers low is disputed. The industry generally claims that Nebraska's electric rates, including industrial, are competitive."[151] In 2017, Senator Justin Wayne testified at the Natural Resource Committee hearing on LB660 that energy prices have actually been trending up.[152]

In 2015, Dr. Ernie Goss reported that although rates are still somewhat competitive, since 2012, Nebraska industrial rates have trended upward to exceed the national average. Between 2008 and 2014 Nebraska's volatility in overall electricity prices was the highest in the region and 45.4% above the regional average.[153] Between 2004 and 2013, the expenditures in electricity for Nebraska's agricultural sector have increased by 107.9%, with a record high of $310.2 million in 2012.[154]The increasing trend in industrial rates is a threat to Nebraska farmers and agriculture producers, particularly because many farmers rely on irrigation systems that are intensive users of electricity.

Nebraska utilities disputed Dr. Goss's assertions, citing the differences in what is classified as "industrial" uses in Nebraska and stating "the EIA places irrigation in the industrial customer category. However, those knowledgeable about the characteristics of building infrastructure and other costs to serve seasonal irrigation versus the characteristics of a typical industrial customer operating 24 x 7, understand the high amount of irrigation served by electrically powered pumping has a substantial impact on the average revenue per kWh, making Nebraska appear far less competitive than it actually is on true industrial

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[149] Testimony of Lanny Nickell, COO, OPPD, Oct. 29, 2021 Hearing on LR136

[150] Transmission upgrades delivering substantial value for Southwest Power Pool members, SPP, January 26, 2016.

[151] Id.; "The EIA places irrigation in the industrial customer category. However, those knowledgeable about the characteristics of building infrastructure and other costs to serve seasonal irrigation versus the characteristics of a typical industrial customer operating 24 x 7, understand the high amount of irrigation served by electrically powered pumping has a substantial impact on the average revenue per kWh, making Nebraska appear far less competitive that it actually is on true industrial rates."

[152] "Costs have been trending upwards since 2008." Testimony of Sen. Justin Wayne at Natural Resource Committee Hearing on LB660, Feb. 16, 2017 (p.2-3)

[153] The Costs and Benefits of Public Power in Nebraska, An Investigation of Electricity Rates, Taxes, and Competitiveness, (p.2) Goss, Ernie, PhD, prepared for Platte Institute 2015

[154] See above.

rates." [155] NPPD also stated that Nebraska's public power generators compete effectively in the SPP Integrated Market, and "The SPP Integrated Market generally ensures the lowest total variable cost, which is made up almost exclusively of fuel costs, for the entire system on a minute-to-minute basis throughout the year."[156]

The 2008/2009 decisions by Nebraska utilities to join the Southwest Power Pool (SPP) occurred in the midst of the time period Dr. Goss was studying. Between 2000 and 2010, the Nebraska Power Review Board was required to hold an annual hearing and issue an annual report to the state that evaluated Nebraska's performance in the area of keeping costs low.[157] The Legislature changed that reporting by the PRB from mandatory to discretionary with LB797 in 2010.[158] No report under Section 70-1003 have been provided by the Board since 2010.

Risks of membership in RTO/SPP

(1) Lack of Local Control. When a public power district (owned by the people) becomes a member of SPP, the power district continues ownership of the facilities, but SPP is given authority to direct and control the load generated by the facility and also weigh in and potentially control the building of future transmission lines.

(2) Directed power outages/blackouts similar to the February 2021 event. During the Feb. 2021 winter storm, Nebraska generated enough power to meet the needs of the entire state but the directions from SPP (an out-of-state entity) were to "shed load" or "curtain generation", both of which had physical, financial, and other impacts on Nebraska ratepayers. The CEO of SPP stated SPP could not guarantee the situation would not happen again. There are examples of similar and more severe rolling power outages in other states.

(3) Decrease or loss of reliability due to de-carbonization goals throughout a regional footprint. Concerns of this nature include those of industry watchers and participants.

NERC released its Long Term Reliability Assessment (LTRA) in December 2021. The assessment does not include recently released generation outlooks for Nebraska. In its report, NERC concluded that the changes that renewables bring to the resource mix is the greatest challenge to reliability of electrical service throughout the United States.[159] SPP was not noted as one of the top 10 areas of concern within the next 10 years, while other regions relied upon by SPP to "fill the gap" during the Feb. 2021 event are. The LTRA identifies numerous risks that stakeholders and policymakers need to focus on over the next

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[155] NPPD responds to Dr. Goss's report states that Nebraska's public power generators compete effectively in the SPP Integrated Market, and "The SPP Integrated Market generally ensures the lowest total variable cost, which is made up almost exclusively of fuel costs, for the entire system on a minute-to-minute basis throughout the year."
[156] NPPD's initial response to "Nebraska Public Power's Competitiveness in the Regional Market" (Report)
[157] Neb. Rev. Stat. §70-1003 Laws 2000, LB901§8
[158] Neb. Rev. Stat. §70-1003, Laws 2010, LB797 §1
[159] NERC, Long Term Reliability Assessment (LTRA), December 2021, p.5, pp. 55-105.

ten years and cautions that those regions not listed as one of the top 10 concerns, are nevertheless at risk due to the interconnectedness of all regions.[160]

In her book, "Shorting the Grid", Meredith Angwin an authority on the grid and one of the first women to be a project manager at the Electric Power Research Institute stated "In the long run, RTO markets punish reliable plants and support greater unreliability plants."[161]

SPP CEO Barbara Sugg stated "Maintaining reliability with this large amount of wind is extraordinary." SPP has increased wind energy and expects to continue to increase reliance on a variable fuel mix. On January 26, 2021, SPP announced it had become "the first regional grid operator with wind as its No. 1 annual fuel source."[162] In the past 10 years, SPP has experienced growth in wind portion of its energy mix from 6% to 31%.[163]

When questioned about how SPP planned to handle the challenge to resiliency in the future, Mr. Nickell responded, "We hope to address it." Mr. Nickell earlier in the hearings stated that SPP "can't guarantee that we won't ever see this [February 2021 event] again."[164] An Electric Power Research Institute (EPRI) representatives reportedly stated at a Nebraska meeting that with zero-carbon goals, Nebraskans should just expect rolling blackouts in the future.[165]

Mr. Nickell supplemented his response in a follow up letter after the October 29 hearing, stating, "SPP's Resource Adequacy process reviews and will continue to review in more detail how increased penetration of renewables impacts the accreditation of those renewable resources and how the planning reserve margin of the system is impacted. Additionally, increased retirements of conventional generation will be more closely reviewed in upcoming planning reserve margin studies." Mr. Nickell also stated that SPP will be working with its members to address the recommendations made in SPP's Comprehensive Review of its responses to the event.[166]

(4) De-carbonization and potential market instability. On Feb. 1, 2021, SPP began operating its new Western Energy Imbalance Service (WEIS) market, kicking off the real-time balancing market with a half dozen regional utilities participating.[167] "SPPs five-minute WEIS intra-hour market 'will greatly aid in the integration of more renewable

160 Id., p. 5

161 Angwin, Meredith, "Shorting the Grid" (p.97). M. Angwin, chemist and project manager at Electric Power Research Institute.

162 SPP becomes first regional grid operator with wind as No. 1 annual fuel source, considers electric storage participation in markets, approves 2021 transmission plan, https://www.spp.org/newsroom/press-releases/spp-becomes-first-regional-grid-operator-with-wind-as-no-1-annual-fuel-source-considers-electric-storage-participation-in-markets-approves-2021-transmission-plan/ January 26, 2021, accessed online 12.1.21

163 Testimony of L. Nickell, Hearing on LR136 October 29, 2021, p.10.

164 Testimony of Lanny Nickell, COO SPP, Oct. 29, 2021 Hearing, p.3

165 Statement conveyed by Sen. Groene at Oct. 29, 2021 Hearing on LR136, p. 20

166 SPP Response to Committee Questions, December 13, 2021.

167 "'This is just the beginning': Southwest Power Pool begins operating Western imbalance market, Robert Walton, Utility Dive, Feb. 2, 2021.

resources' . . . [t]he utility has been adding green power and making plans to shutter coal generation."[168]

Each of Nebraska's utilities has de-carbonization goals which include increased use of renewables, which may result in the unviability and closure of facilities utilizing what are considered traditional and reliable resources for baseload generation. A perceived acceleration of de-carbonization goals brings with it concerns from some clean energy advocates that SPP's new market creates a transmission seam across Colorado and may not be as efficient as single RTO serving the state.

Hawaii's Clean Energy Initiative sets a goal of 70 percent carbon dioxide emission free energy by 2030, and 100 percent by 2045. Having achieved a consolidated 34.5% renewable portfolio in 2020, the initiative is finding it difficult to meet those goals going forward. [169], [170]

WEIS representatives state similar concerns for other utilities, but stating "Utilities that join the SPP WEIS are sure to find what utilities (balancing authorities) have found in the California Energy Imbalance Market, significant measurable saving for customers . . . and reliability will be improved through their ability to purchase resources every five minutes to meet imbalances in their system, rather than hourly."[171]

On the other hand, NERC points out that "[d]iminished levels of flexible generation--fuel-assured, weatherized, and dispatchable resources--create vulnerabilities to energy shortfalls when extremely hot or cold weather settles over a wide area for extended duration or when weather-dependent generation is impacted by abnormal atmospheric conditions, such as smoke or wind drought."[172]

(5) Nebraska Ratepayers Pay for investment in other states' assets. SPP directs the building of new transmission lines. Currently, there are multiple projects outside of Nebraska that Nebraska taxpayers are paying for because Nebraska shares the cost as a member of SPP.[173] The shared costs of new infrastructure is also listed as a benefit should there be new transmission line projects in Nebraska.

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[168]Duane Highley, CEO, Tri-State Generation and Transmission Association, Southwest 'this is just the beginning'" Southwest Power Pool begins operating Western imbalance market, Robert Walton, Utility Dive, Feb. 2, 2021.

[169] Clean Energy Mandate Proving Difficult for Hawaii, Duggan Flanakin, Environ. & Climate: News, November 19, 2021. https://heartlanddailynews.com/2021/11/clean-energy-mandate-proving-difficult-for-hawaii/

[170] Clean Energy Mandate Proving Difficult for Hawaii, Duggan Flanakin, Environ. & Climate: News, November 19, 2021.

[171] Ormond, Amanda, managing director Western Grid Group; Id.

[172] NERC, Long Term Reliability Assessment (LTRA), December 2021, p6.

[173] Colloquy between Sen. Wayne and Lanny Nickell, COO, SPP, Oct. 29, 2021 Hearing on LR136, P.44-45.

(6) Market manipulation: There have been examples that FERC and the RTOs can "manipulate the market power issue," including how the clearing price is set, and there are claims they do.[174] In her book, "Shorting the Grid" Angwin concurs, stating "Auctions work for the RTOs. Because of many clearing prices they generally are found to cause RTOs to buy at higher rates, which are then passed on to the end user." No evidence has been presented to indicate that the market was manipulated during the Feb. 2021 event.

(7) Closure of more stable power generation sources. [175] De-stabilization of the power grid has been a growing concern with the increased use of regional transmission organizations, growing dependence on renewable energy resources, and retirement of generators of more stable resources such as coal-powered and nuclear power plants.[176]

SPP's five-minute WEIS intra-hour market "will greatly aid in the integration of more renewable resources," Tri-State CEO Duane Highley said in a statement. The utility has been adding green power and making plans to shutter coal generation.[177]

In Feb. 2014, U.S. Senator Lisa Murkowski issued "An Energy 20/20 White Paper, in which she noted increased reliability in electricity to that point, but cautioned, "there are new factors and forces that are rapidly changing our energy supply mix in a manner that could fundamentally alter or degrade the system all segments of the industry have so carefully built. Among these are a mass of new environmental regulations that have contributed to the closure of many existing power plants and threaten to impact even more, and increasingly, subsidies and preferences for certain forms of power generation and use that may be leading to unintended consequences."[178]

"Reliability begins by choosing the best generation resource for our system needs."[179] In 2015, "Nebraska's generation mix was a diversified portfolio of resources which included coal (73 percent), nuclear (17 percent), natural gas (4 percent), hydroelectric (4 percent), and renewable resources (2 percent)".[180]

By 2020, Nebraska obtained 51% of its in-state electricity net generation from coal, 24% from wind, and 17% from nuclear power. Almost all of the rest was generated from hydropower (4%) and natural gas (4%).[181]

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174 Angwin, Meredith, "Shorting the Grid", p. 96.

175 Angwin, Meredith: The electric grid and reliability. Nuclear News, June 24, 2021

176 Senate Energy and Natural Resources Committee Hearing, January 23, 2018; "Powering The Future: Ensuring that Federal Policy Fully Supports Electric Reliability, An Energy 20/20 White Paper, U.S. Senator Lisa Murkowski, 113th Congress, February 2014; Nebraska Renewable Energy Exports: Challenges and Opportunities (LB 1115 Study, The Brattle Group, December 12, 2014.

177 Walton, R., 'This is just the beginning'. Southwest Power Pool begins operating Western imbalance market." Dive Brief. Feb. 2, 2021

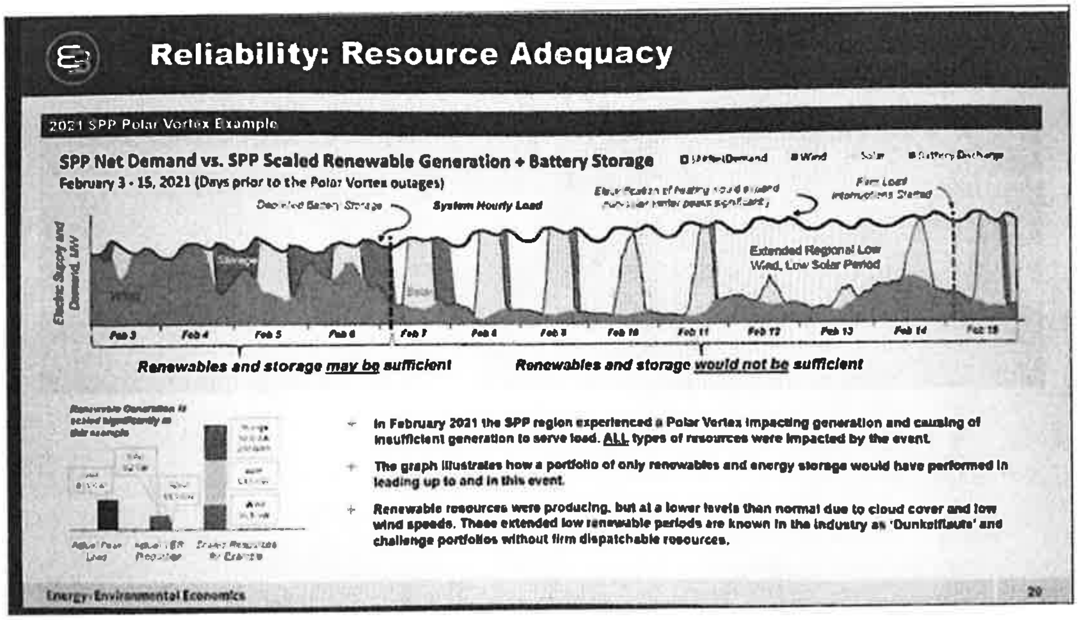
178 Powering the Future: Ensuring That Federal Policy Fully Supports Electric Reliability, U.S. Senator Lisa Murkowski, 113th Congress. An Energy 20/20 White Paper February 2014.

179 Reliable Electricity is a Cornerstone of Public Power. Working for Nebraska.
Designed and Developed by GenR8 Marketing | Privacy Policy

180 Id.

181 U.S. Energy Information Administration (EIA), Profile: Quick Facts. https://www.eia.gov/state/?sid=NE last updated May 20, 2021, accessed Dec. 8, 2021.

(8) Decreased reliability as renewable resources grow. The Reliability: Resource Adequacy graph below depicts E3's model of how a portfolio of only renewables and energy storage would have performed leading up to the Feb. 2021 event. It notes that "Renewable resources were producing but at a lower level than normal due to cloud cover and low wind speed" which "challenged portfolios without firm dispatchable resources."[182]



COSTS OF WITHDRAWAL FROM SPP: If there is consideration of withdrawal from SPP, the costs involved will necessarily also be part of the discussion.

In 2016, SPP reported that "more than $240 million in annual fuel cost savings [was] realized due to transmission investments during 2012-2014.

In response to Committee requests for information, SPP reported that withdrawal from SPP would be "unprecedented" and would "fundamentally split SPP in half," and " even if Nebraska is no longer part of SPP, current Nebraska members have a legal obligation under federal law to provide open access to transmission to surrounding providers. This would mean that the utilities must offer transmission access to others on essentially the same terms it provides transmission service to its own customers."[183] According to SPP, the breakdown of these fees at present value, with an 8% discount rate would be:

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[182] Produced by E3 Solutions, e3solutionsne.com; Discussed in Oct. 29, 2021 Hearing on LR136, p45-46.
[183] SPP LR136 response re SPP exit costs, attachment 1 September 30, 2021.

ESTIMATED DATA	Transmission Obligations	Corporate Debt Obligation	Total
OPPD	$254 million	$9.3 million	$263.3 million
NPPD	$318.3 million	$9.3 million	$327.6 million
LES	$91.5 million	$3.4 million	$94.9 million
TOTAL	$663.8 million	$22 million	$685.8 million

Notice Requirement. Under the SPP Membership Agreement, "Depending on a member's specific registration in SPP and their related service agreements, termination of membership in SPP requires a minimum of 24 months written notice and payment of exit fees to meet the member's obligation to hold users harmless."

While exiting SPP is possible, SPP proposes that taking the action poses particular issues for Nebraska beyond the association exit fees, stating, "The first question is--what conditions would precipitate a withdrawal from SPP and payment of the associated exit fees? The second question is-- what are the alternatives to SPP and what happens next? Or perhaps stated another way—what problem would be remedied by leaving SPP and is there a better option to resolve that problem? The alternatives to SPP are limited: 1) Nebraska could attempt to operate as its own RTO, but this brings with it the immense complexity and expense of standing up a new region, plus you'd forego a larger region to fall back on should Nebraska ever experience local reliability challenges; or 2) The Nebraska utilities could join MISO, an even more peculiar option that provides no functional difference and was originally judged to be less beneficial than membership in SPP. In addition to creating its own set of challenges, you'd be paying the SPP exit fees to enable a lateral move to another RTO with yet its own set of exit fees, all based on a similar construct to SPP."[184]

Directive 8: Examine the authority of public power districts within the state of Nebraska to join and enter into agreements with regional transmission organizations such as SPP.

The Power Review Board was established and granted oversight powers by Legislature in 1963[185]. The Nebraska Supreme Court has repeatedly recognized authority granted to the Power Review Board.[186]

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[184] SPP LR136 response re SPP exit costs, September 30, 2021, Attachment.
[185] Neb. Rev. Stat. §1003, Laws 1963, c. 397, §3, p.1260.
[186] "This court cannot interfere with a decision of the Power Review Board (within its limited jurisdiction) unless there is no evidence to sustain the action of the board or, for some other reason, the record shows the action of the board is arbitrary and unreasonable."

On May 9, 2008, the Nebraska Power Review Board (PRB) passed Resolution 08-58 authorizing Nebraska public power districts and legal counsel to pursue membership in the Southwest Power Pool.

On September 11, 2008, PRB adopted Resolution 08-111, recognizing that negotiations between the entities and SPP had taken place and resulted in preparation of a Membership Agreement, which was reviewed and approved by the Board, the power districts, and SPP. [187]

Each of the three major public power districts (LES, NPPD, and OPPD) signed Membership Agreements with Amendments between September 15 and September 26, 2008 [188] On September 30, 2008, SPP filed an application with FERC for amendments to its agreements and bylaws, with an effective date of April 1, 2009 as the effective date.[189]

<u>Directive 9:</u> Examine whether there was any weather-induced generation reduction from the extreme cold of February 2021 and what impact it had on energy resources.

The full impact on costs, reliability, and finances, to Nebraska ratepayers is not readily known at this time. It is known that less gas than expected by SPP was actually delivered. It is also known that Nebraska produced energy sufficient for its needs. Natural Gas prices increased, communities had to "shed load", and some had to "curtail generation," The generation reduction was indirectly caused by the weather because of the challenges being experienced by other states on the SPP grid footprint.

In 2000, LB901 set forth a policy that the state prepare for an evolving retail electricity market, and whether retail competition is in the best interests of the citizens of Nebraska. An annual hearing and report about the criteria was required.[190] In 2010, LB797 made the inquiry and report discretionary. No further reports are on records as being received since LB797 took effect.[191]

Nuclear power and coal plants provide the most dependable resources during cold weather events. [192] The same was true in the Southwest Power Pool (SPP) footprint, during the

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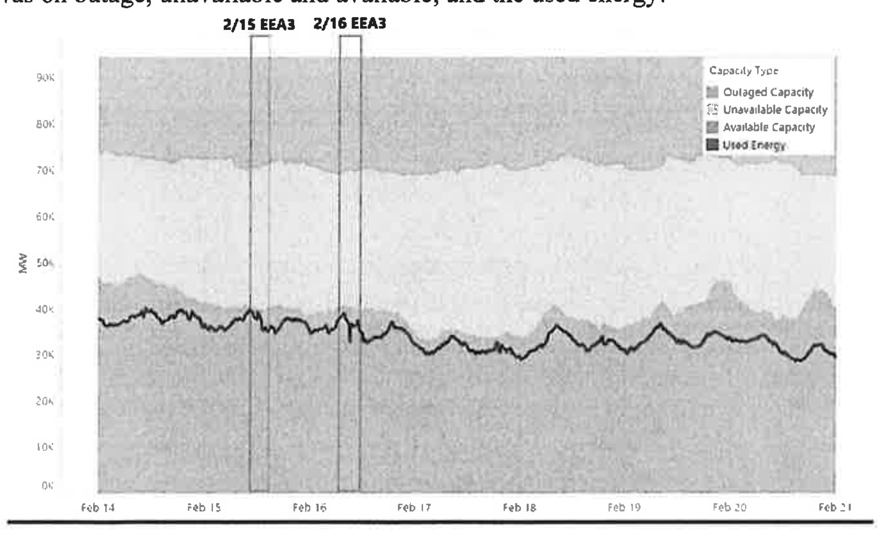
[187] Southwest Power Pool, Inc., Membership Agreement with NPPD, p.31m 2008.
[188] Membership Agreements and "Amendments to SPP Membership Agreements.
[189] FERC filing related to materials for LES, NPPD, and OPPD, September 30, 2008.
[190] Laws 2000, LB901, Sections 7 and 8
[191] Laws 2010, LB797, Section 1
[192]Energy.gov; https://www.energy.gov/science-innovation/energy-sources/nuclear; Adam, Rod. Atomic Insights, Performance of the New England power grid January 26, 2018 (Gordon van Weile, president and CEO of ISO-NE indicating he had been sounding the warnings since at least 2013).

February 2021 cold weather event. At the same time, "In Nebraska, renewables, including wind energy, are reducing the amount of generation at coal-fired power plants, but the dispatchable capacity provided by facilities like Gerald Gentleman Station and Sheldon Station is essential to the market."[193] There appears to be insufficient natural gas available to compensate for insufficiency of baseload should reliance on renewable generation continue to grow while current baseload generating facilities continue to be shuttered.

In short, as the fuel mix decreases in use or availability of stable and reliable energy generating assets like coal, natural gas, oil, and nuclear facilities, and increases in more unreliable, but subsidized resources, like wind and solar, it becomes more and more difficult to ensure that electricity flow will be continually reliable. "Reliability begins by choosing the best generation resource for our system needs." [194] Nebraska's generation mix is diversified,"[195] "Base load resources like coal, nuclear, natural gas, or hydroelectric power can run continuously and can be actively controlled to follow load and meet consumer demand. Variable resources like wind and solar, however, rely on environmental conditions which can be hard to reliably predict." Increases of non-dispatchable generation also poses issues with flow of power on the grid. "During the periods on Feb. 15 and 16 when SPP declared an EEA 3, approximately 42% of nameplate capacity was available on average. The total amount of generation available during these time frames constituted approximately 65% of SPP's accredited capacity, with 87-88% of that available generation provided by accredited resources"

Following are graphs and text provided by SPP in its Comprehensive Review relative to accredited capacity versus available capacity of fuel types[196]

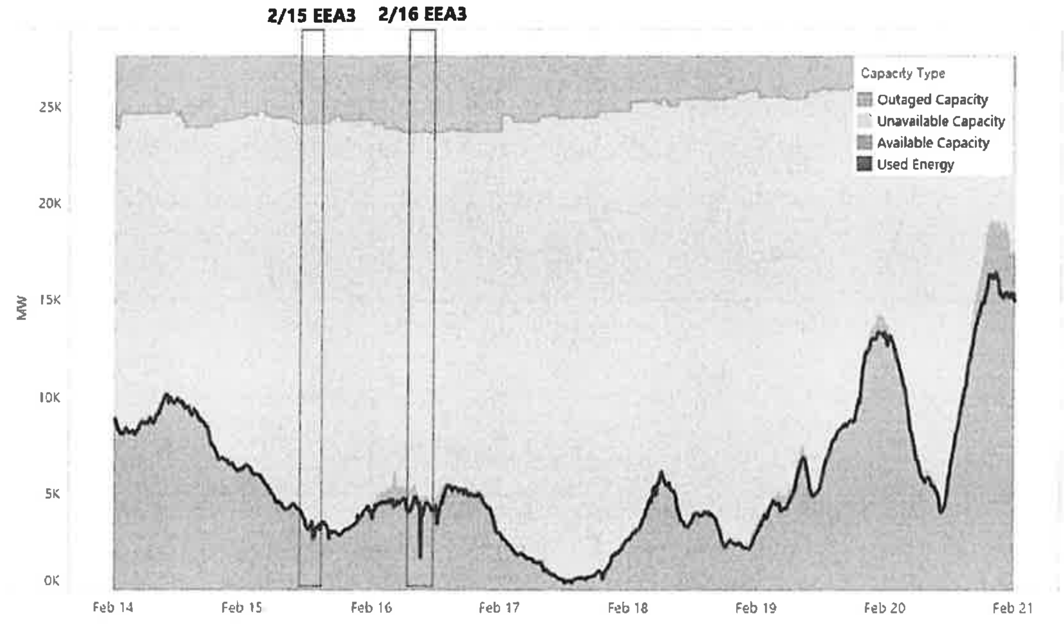
Figure 22 found on page 48 of the SPP report shows the status of generation capacity in SPP, distinguishing capacity that was on outage, unavailable and available, and the used energy.



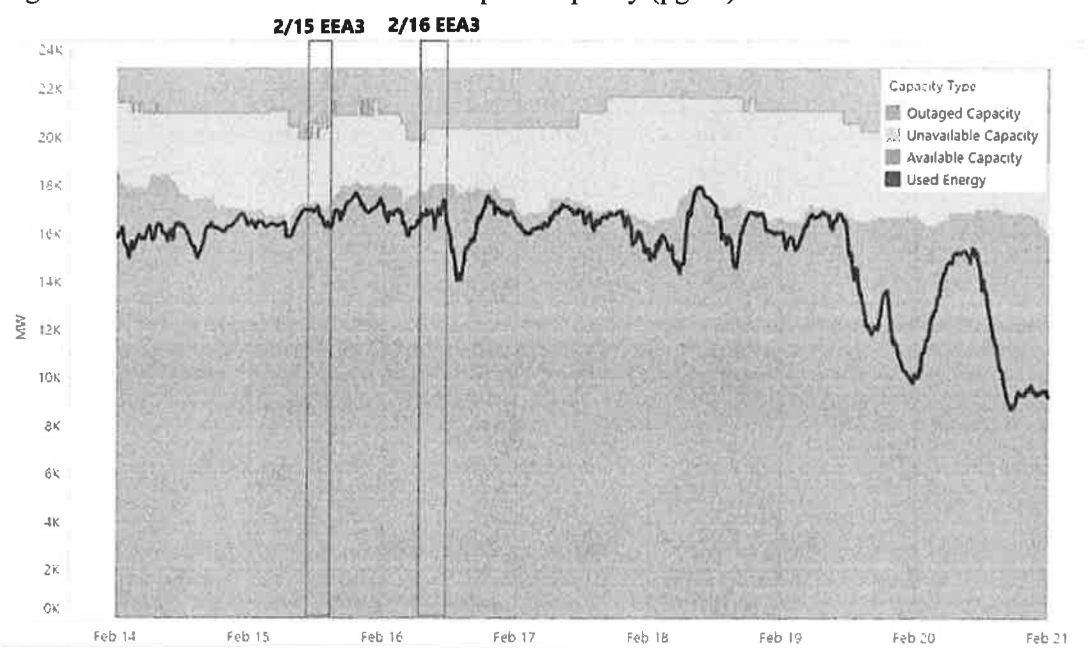
[193] NPPD's initial response to "Nebraska Public Power's Competitiveness in the Regional Market" (Report 7/2021)
[194] "Reliable electricity is a cornerstone of public power." NREA, Working for Nebraska, July 26, 2021
[195] NREA, Working for Nebraska, July 26, 2021
[196] "A Comprehensive Review – Response", Southwest Power Pool, July 19, 2021 pg. 49.

"[W]ind generation was 12-16% of nameplate capacity, available on average during the event. The total amount of wind energy produced on average during these time frames constituted approximately 79-101% of accredited wind capacity, with 43-54% of that energy provided by accredited resources.

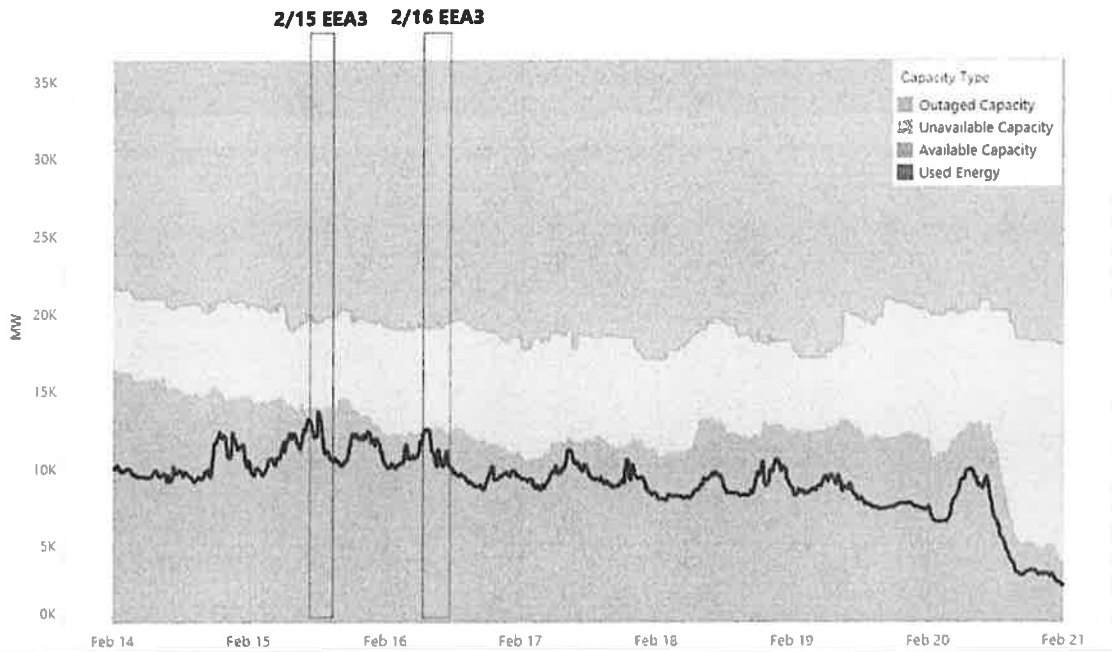
Figure 23, found on p.47 of the SPP report, shows available and unavailable wind generation capacity during the February 2021 event.



Coal generation was about 77-79% of nameplate capacity (pg.49):



Gas generation, about 34-37% of nameplate capacity (pg. 49):



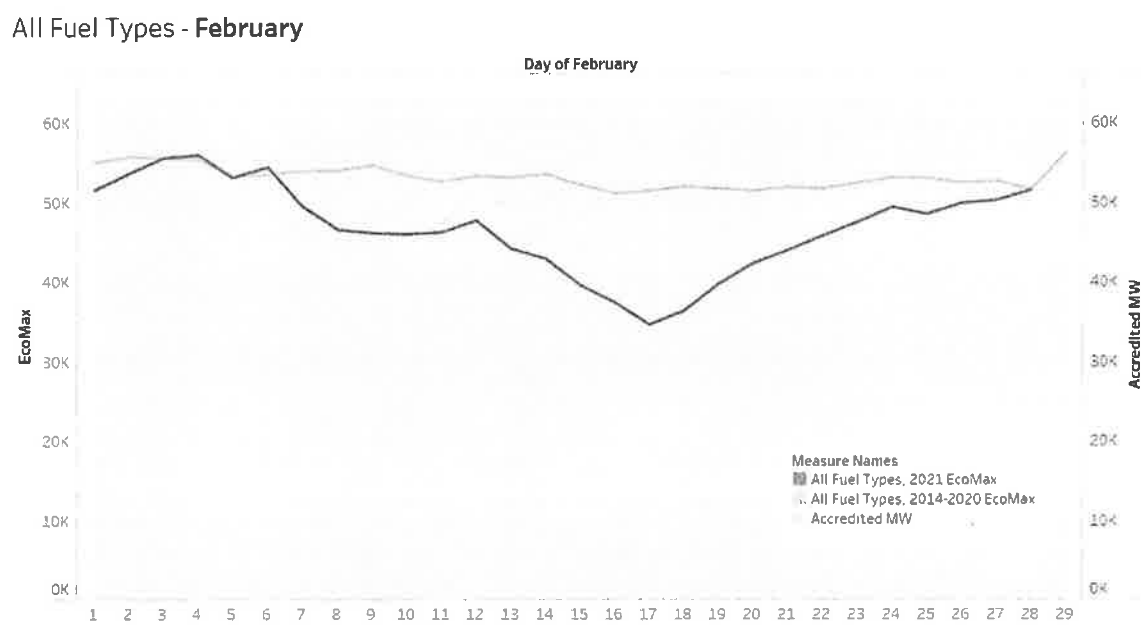


Figure 26: February 2021 available capacity as compared to prior year average[197]

[197] "A Comprehensive Review- Response" Southwest Power Pool, July 19, 2021, pp 48-50

Directive 10: Any alternatives and mitigation measures to avoid rolling power outages in Nebraska in the future, including requirements to develop robust baseload capacity in the regional marketplace and the degree to which it may be helpful to develop micro-grids using advanced nuclear reactor technology in Nebraska.

The primary focus for many of the measures found was working to ensure stable and consistent reliability of baseload generation Research and other suggestions that may be of interest to lawmakers working to avoid rolling power outages in Nebraska in the future include

1. Creating clearly defined state standards for "adequacy"," reliability," and/or "best interests" of rate-payers.

   SPP reported that one of the recommendations coming out of its task force was to improve its resource availability, and increasing the percentage of reserves required or accredited capacity policy of the types of generation may be something SPP "grapples" with as the recommendation is considered. [198]

   MISO has developed its Reliability Imperative, which defines and describes actions MISO is taking to ensure the current and future reliability of the grid. The imperative focuses on preparing the region for a future with a different risk profile stemming from a high penetration of renewables, which are variable rather than dispatchable resource and looks at enhancements to plan, market, operations, and systems; changes that it is perceived will also be needed to maintain reliability of the region during more frequent extreme weather events in the future.[199] MISO's reliability imperative operates on the basis that members, state regulators, and other entities responsible for reliability all have a shared obligation to work together to address the challenges.
2. Consider "reliability"-based incentives similar to "production based incentives currently available in the industry. In answer to Sen. Bostelman's inquiry into this as a possibility, Mr. Nickell stated that this consideration is part of the SPP recommendations.[200]
3. Requirements to develop robust baseload capacity in the state or regional market place. Although Mr. Nickell mentioned the possible consideration of "get benefit to generators who have dual-fuel capability," there is a question about whether FERC rules would allow SPP or its members to favor one regulated form of generation over another.[201] SPP recognized the need to reconsider how it approaches the load shedding process in the region.

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[198] Testimony of Lanny Nickell in response to question from Sen. Moser, Hearing Oct. 29, 2021, p.10-11.
[199] The February Arctic Event February 14-18, 2021, MISO,
[200] Testimony of L. Nickell, CEO of SPP, Oct. 29, 2021 Hearing on LR136, p. 15
[201] FERC rule prohibiting energy discrimination.

4. RTO use of switches that can separate portions of the footprint experiencing challenges that may negatively affect the remainder of the footprint. Sen. Wayne inquired whether SPP had any way to do this and whether it intended to explore the option. Mr. Nickell indicated there are no current plans to do this but it may be an idea to be considered.[202]
5. Explore and develop policies to answer the questions about whether allowing retirement or closure of "certain generation that provides the reliability balance" needed.[203]
6. Encourage development of micro-grids using advanced nuclear reactor technology in Nebraska. A micro-grid is a local energy grid with control capability, which can be used in case of emergency. While it is generally connected to the grid, a micro-grid can be disconnect from the traditional grid and operate autonomously.[204] The grid is an interconnection of generators and end users. When a portion of the grid needs to be repaired, everyone on the grid is affected. The period of operation time is dependent upon how the micro-grid is fueled. Notably, the Dept. of Energy recognizes that optimizing technology associated with micro-grid research and related projects may be financially unbearable, or of risk greater than the private sector can bear, may require public investment and public-private partnerships.[205] Power outages in states like California and New York have sparked investment by companies like Home Depot in micro-grid development of their own, and formation of companies devoted to marketing turnkey solutions to commercial interests.
7. Caps on percentage of base-load generation from resources other than coal-generated, nuclear-powered, or hydro.
8. Develop guidelines and resource assessment standards for measuring progress or limitations with fuel mix goals.
9. Re-establish full local control of decisions to dispatch energy resources by encouraging and/or requiring taxpayer owned utilities to withdraw from SPP and remain independent of any other out-of-state entity that gains decision-making authority over power available to Nebraska ratepayers. There were a number of issues examined before Nebraska utilities became members of SPP and there are a number, in addition to costs, that will need to be included if withdrawal from SPP is considered. Before entering agreements with SPP in 2008, LES, NPPD, and OPPD considered membership in either SPP or MISO
. The entities chose SPP based on lower projected costs, governance structure, wholesale market opportunities to enhance transmission interconnections and wholesale market opportunities to the south. Based upon estimates provided by SPP, the aggregate SPP exit fees for the transmission-owning Nebraska members would be approximately $685.8 million."[206]
10. Establish new RTO within surrounding states north to south.

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[202] Colloquy between Sen. Wayne and L. Nickell, October 29, 2021 Hearing, p. 26-29.
[203] Testimony of Lanny Nickell, COO, SPP Oct. 29, 2021 Hearing on LR136, p. 18
[204] How Microgrids Work, U.S. Department of Energy, June 17, 2014.
[205] How Microgrids Work, U.S. Department of Energy, June 17, 2014.
[206]SPP LR136 response at p.2, noting estimates and stating "these estimates do not represent all of the costs associated with exiting SPP and pursuing an alternative."

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APPENDIX NO. 1

CHAIRMAN BOSTELMAN'S MEMO
MAY 4, 2021

APPENDIX "1"
May 4, 2021 Memo to Committee

MEMORANDUM

TO: NATURAL RESOURCES COMMITTEE MEMBERS
FROM: SEN. BRUCE BOSTELMAN, CHAIRMAN
DATE: May 4, 2021
SUBJECT: LR48

As you are aware, the extreme weather event the week of February 14, 2021 triggered rolling power outages in parts of Nebraska. As a result, the Natural Resources Committee held a public hearing on March 3, 2021 to receive requested testimony on LR48. I invited testifiers from small and large public power district representatives, as well as someone from the Southwest Power Pool. The focus of the hearing was to discover and seek understanding of the reasons for the rolling power outages experienced by Nebraskans on February 15-16, 2021. Members of this committee requested informational documents from testifiers at that hearing and much has now been received and distributed. Many questions still remain.

Background

In response to the questions arising related to the rolling power outages experienced by communities in Nebraska February 15 and 16, 2021, this Committee filed Legislative Resolution 48 and scheduled a hearing with various public power districts, which took place on March 3, 2021. The primary focus of this hearing was to learn and understand the weather event and circumstances surrounding the reported "shed load" orders issued by Southwest Power Pool to its Nebraska members.

I extended an invitation for in-person testimony to representatives who appeared as follows:

Mark Kirby, General Manager, Butler County Public Power
Kevin Wailes, CEO, Lincoln Electric System
Tom Kent, President & CEO, Nebraska Public Power District
Tim Burke, President & CEO, Omaha Public Power District
Lanny Nickell, Exec. Vice President & COO, Southwest Power Pool (SPP)

Testimony: Testimony and materials were provided by the public power districts, including follow up documentation requested by members of the Committee and sent after the hearing pursuant to a follow up request, a copy of which is attached. Materials have been distributed to all committee members and remain a part of each member's notebook that is held by the Committee Clerk Katie Bohlmeyer. Documents in response to requests concerning costs associated with the event and final reports have not yet been received and are not anticipated before July 2021. What was received revealed the following:

1. The public power entities were aware of an arctic weather front approaching and predicted to cover Nebraska as it stretched from North Dakota to Texas.
2. Nebraska generated sufficient energy within its borders to meet the needs of the State.
3. Southwest Power Pool (SPP) is a Regional Transmission Organization with a goal of balancing transmissions among its 14 state members.
4. Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), and Lincoln Electric System (LES) are all members of SPP.
5. SPP ordered some of its members to "shed load", or to shut down transmissions to certain areas in order to protect against imbalances and as part of the members' agreements with SPP, the members were required to execute the directive within a short period of time, resulting in rolling power outages to certain Nebraska residents throughout the State.
6. SPP also ordered at least one member in Nebraska to cease generation of power at various times during the event.

A master file/notebook copy held in the office of Committee Legal Counsel will be updated as new materials are received and will remain available in the office should any member wish to review that file.

Further power outage threats many questions were asked at the hearing and continue to be asked by members of the Legislature about the potential for future outages of the sort experienced in February and whether there are ways the Legislature can and/or should act to minimize any such future risk.

In addition to the anticipated reports, I have discussed with others an interim study to thoroughly understand the event, along with the authority, benefits, and/or disadvantages of continuing membership in SPP and to evaluate potential ways to protect Nebraskans against a repeat of any disruption of service.

A Legislative Resolution for the interim study will be filed prior to day 80 of the current Legislative Session and a plan to conduct the study is being developed. The background material and testimony gathered for LR48 will be included in any final report on the interim study.

Please let my office know if you have any questions. You are welcome to call Committee Legal Counsel Cyndi Lamm at 402.471.2719 with any questions, issues, or ideas.

Sincerely,

Sen. Bruce Bostelman
Chairman, Natural Resources Committee

APPENDIX NO. 2

TRANSCRIPT OF HEARING
OCTOBER 29, 2021

(Available online at
Nebraskalegislature.com LR136 2021

APPENDIX "2"

TRANSCRIPT OF HEARING

OCTOBER 29, 2021

Transcript Prepared by Clerk of the Legislature Transcribers Office
Natural Resources Committee October 29, 2021
Rough Draft

BOSTELMAN: If you could take your seats, we'll get started here. Thank you, everyone, welcome to the Natural Resources Committee. I am Senator Bruce Bostelman from Brainard, and I represent the Legislative District 23. And I serve as the Chair of this committee. We're going to hear testimony today on LR136, which was introduced by Senator Brewer, cosponsored by Senator Clements, Erdman, Gregory-- Gragert and Halloran. The purpose of this interim study is to examine, understand and evaluate the causes, impacts and costs of rolling electrical power outages during the extreme weather events of February, 2021. The study shall also identify and evaluate the differing effects, if any, of public power district membership in the Southwest Power Pool, and the costs and benefits of SPP memberships. The testimony received today will be through invited testifiers only, as noted at the door. We do have that list on the door, correct? OK, as noted at the door. And I ask that you abide by the following procedures to better facilitate today's proceedings. Please silence or turn off your cell phones; and I will ask each testifier to come up, give their prepared testimony based on their questions asked of them beforehand. For committee members, if you go into your book binder behind the last thing, under LR136 are the questions that they'll be talking to. Once they are done, the senators will be given a chance to ask questions. When you come to the, to testify, please clearly, speak clearly into the microphone. Tell us your name and please spell your first and last name to ensure we get an accurate record. Senator Brewer is joining us on the committee today as the sponsor of the LR. The committee members with us today will introduce themselves, starting on my left with Senator Wayne.

WAYNE: Senator Justin Wayne, District 13, which is north Omaha, northeast Douglas County.

J. CAVANAUGH: John Cavanaugh, District 9, which is midtown Omaha.

MOSER: Mike Moser, District 22, which is Platte County and a little bit of Stanton County.

BOSTELMAN: And on my right, Senator Brewer.

BREWER: Tom Brewer, representing 43rd Legislative District, and the Chair of the Government Committee.

HUGHES: Dan Hughes, District 44, 10 counties in southwest Nebraska.

GROENE: Senator Groene, District 42.

APPENDIX NO. 3

TRANSCRIP OF HEARING (LR48)

MARCH 3, 2021

(Available online at Nebraskalegislature.com (LR48 2021)

APPENDIX "3"

TRANSCRIPT OF HEARING (LR48)

MARCH 3, 2021

Transcript Prepared by Clerk of the Legislature Transcribers Office
Natural Resources Committee March 3, 2021
Rough Draft

Does not include written testimony submitted prior to the public hearing per our COVID-19 response protocol

BOSTELMAN: So, need to do some COVID procedures first over that. For the safety of our committee members and staff, pages and the public, we ask those attending our hearing to abide by the following procedures. Due to social distancing requirements, seating in the hearing room is limited. We ask that you only enter the hearing room when it is necessary for you to attend the bill hearing in progress. The bills will be taken up in order posted outside of the room and that will be the invited testimony specific today, those individuals, as posted, are welcome to come up in order. A request that everyone utilize identified entrance and exit doors-- entrance and exit doors to the hearing room. And we ask that you wear a face covering while in the hearing room. Testifiers may remove their mask-- their face mask covering during testimony to assist committee members and the transcri-- transcribers in clearly hearing and understanding the testimony. Pages will sanitize the front table and chair between testifiers. Public hearings for which attendance reach a seating capacity or near capacity, the entrance door will be monitored by a Sergeant at Arms who will allow people to enter the hearing room based upon seating availability. Persons waiting to enter a hearing room are asked to observe social distancing and wear a face covering while waiting in the hallway or outside of the building.The Legislature does not have the availability due to the HPAC project of an overflow hearing room for brief-- for hearings, which attract several testifiers and observers for hearings with a large attendance, we request only testifiers enter the hearing room. Want to welcome everyone to the Natural Resources Committee. I am Senator Bruce Bostelman and I am here from Brainard and I represent Legislative District 23. I serve as the Chair of this committee. I ask that you abide by the following procedures to better facilitate today's proceedings. Please silence-- silence or turn off your cell phones. When you come to testify, please speak clearly into the microphone, and I want to reiterate that loud and clear is very important. It is difficult for us to hear and if you would please do that. You may remove your mask and tell us your name and please spell your first and your last name to ensure we get an accurate record. Today is for invited testifiers only. The order of testifiers is as follows: Mark Kirby, Kevin Wailes, Tom Kent, Tim Burke and Lanny Nickell. No displays of support or opposition to a bill, vocal or otherwise, is allowed at a public hearing. Testifiers will have 10 to 15 minutes to

APPENDIX NO. 4

SPP LR136 Responses to Committee Re SPP exit costs,

September 30, 2021

Attachment 1

LR 136
Responses to the Committee Chair

LR 136 is an interim study resolution introduced by Senators Brewer, Clements, Erdman, Gragert and Halloran to examine and evaluate the causes, costs, and impacts of rolling electrical power outages during the extreme weather events of February 2021. The resolution was referred to the Natural Resources Committee.

Senator Bostelman, Chair of the Natural Resources Committee, requested our responses to the following questions:

1. What, if any, are hard costs associated with pulling out of SPP assuming all procedures are followed? (Please provide the SPP exit fee, knowing that the final number will be negotiated.)
2. What process is required? (We have the membership agreement, but breaking it down to reality of expectations will be helpful.)
3. How much time would it take each public power entity to withdraw under the standard agreement?

As we discussed in our materials provided to the committee for LR 48, regional transmission organizations (RTOs) began to emerge in the late 1990's and early 2000's following congressional passage of various Energy Policy Acts and a series of related orders issued by the Federal Energy Regulatory Commission (FERC) that drove their adoption and govern their operation. As a result of the movement towards federally-regulated RTOs, the Mid-Continent Area Power Pool (MAPP), of which Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), and Lincoln Electric System (LES) were long-time members, ultimately ceased its RTO functions in 2001. NPPD, OPPD and LES then began to look at other options for maintaining these critical services.

After evaluating membership in both SPP and the Midwest Independent System Operation (MISO), NPPD, OPPD and LES all joined the Southwest Power Pool (SPP) in 2009, and the Municipal Energy Agency of Nebraska (MEAN) joined in 2015. Reasons for joining SPP included lower projected costs compared to MISO, governance structure advantages, better wholesale market opportunities to enhance transmission interconnections and wholesale market opportunities to the south.

SPP performs numerous critical and complex functions on behalf of its members, including balancing load and generation, coordinating a regional response to maintain grid reliability, and directing regional transmission expansion efforts. In each of these various roles, SPP is continuously making financial commitments based on a stakeholder process on behalf of all its members, including capital construction, increased administrative costs, etc. Exit fees, or withdrawal fees, are then required to ensure a departing member makes good on its share of SPP's existing financial obligations. While exit fees pose a significant burden for an exiting RTO member, they also serve to protect the remaining members from significant cost shifts.

Based upon estimates provided by SPP, the aggregate SPP exit fees for the transmission-owning Nebraska members are approximately $685.8 million, but these estimates do not represent all of the costs associated with exiting SPP and pursuing an alternative. More detail on the breakdown of these fees is provided below and a discussion of the other cost considerations, which would likely be more than the exit fees, is included in Attachment 1.

ESTIMATED DATA	Transmission Obligations	Corporate Debt Obligation	Total
OPPD	$254 million	$9.3 million	$263.3 million
NPPD	$318.3 million	$9.3 million	$327.6 million
LES	$91.5 million	$3.4 million	$94.9 million
TOTAL	**$663.8 million**	**$22 million**	**$685.8 million**

*Present value fee estimate at an 8% discount rate

Depending on a member's specific registration in SPP and their related service agreements, termination of membership in SPP requires a minimum of 24 months written notice and payment of exit fees to meet the member's obligation to hold users harmless. More background on this process is provided in Attachment 2.

While exiting SPP is possible, it begs a couple of questions. The first question is--what conditions would precipitate a withdrawal from SPP and payment of the associated exit fees? The second question is--what are the alternatives to SPP and what happens next? Or perhaps stated another way—what problem would be remedied by leaving SPP and is there a better option to resolve that problem?

The alternatives to SPP are limited: 1) Nebraska could attempt to operate as its own RTO, but this brings with it the immense complexity and expense of standing up a new region, plus you'd forego a larger region to fall back on should Nebraska ever experience local reliability challenges; or 2) The Nebraska utilities could join MISO, an even more peculiar option that provides no functional difference and was originally judged to be less beneficial than membership in SPP. In addition to creating its own set of challenges, you'd be paying the SPP exit fees to enable a lateral move to another RTO with yet its own set of exit fees, all based on a similar construct to SPP. Again, these complications and more are discussed in greater detail in Attachment 1.

We have provided the requested information regarding the estimated fees and process for withdrawing from SPP, but we believe any consideration of leaving SPP is seriously misplaced. Could SPP have done some things better during the February event? Absolutely. But did SPP successfully coordinate and maintain system integrity across the entire region while faced with one of the most extreme reliability challenges in recent times? Without a doubt. Working towards the continual improvement of SPP processes should be the goal following this event, not picking up our ball and going home. Any alternative to continued membership in SPP would require significant exit payments, further compounded with new complications and expenses, and all for something that would have a far greater chance of being worse for Nebraska utility customers than an improvement.

[Submitted to the Natural Resources Committee on behalf of Nebraska's largest SPP members.]

ATTACHMENT 1

Attachment 1

Impacts and considerations of withdrawing from SPP

A question has been raised regarding the cost consequences should Nebraska's electric utilities withdraw from the Southwest Power Pool (SPP). Such a withdrawal from the SPP integrated market would be without precedent and would raise significant issues both operationally and financially. First, Nebraska is located generally in the middle of the SPP geographic footprint. If Nebraska's utilities withdraw, it fundamentally splits SPP in half. Under federal law, even if Nebraska is no longer part of SPP, its transmission owning utilities have a legal obligation to provide open access to transmission meaning the utilities must offer transmission access to others on essentially the same terms it provides transmission service to its own customers.

Second, depending on the voltage, transmission within SPP has been developed on a cost share basis so that certain additions by particular utilities/owners will be partially paid for by others in the SPP footprint who benefit from the enhanced network which delivers benefits throughout the footprint. The costs associated with these upgrades are paid for through annually-set transmission rates which collect costs over decades. Certain Nebraska transmission projects will receive the overwhelming majority of funding from outside Nebraska under the cost sharing formula applicable to a particular project. Similarly, Nebraska utilities are expected to pay their pro rata share of projects over time. How one unwinds the multiple long-term financial commitments that have been made would require extensive discussion and negotiation and has the potential to result in litigation.

Third, Nebraska would no longer benefit from the consolidated balancing area provided by the much larger SPP footprint. Prior to joining SPP and its establishing a single balancing area, the three Nebraska utilities operated their own balancing areas. Under federal laws, the operator of a balancing area is responsible for assuring reliability of the system meaning the generation must constantly match the load in the balancing area and must be prepared to address the sudden loss of the largest generator on the system. In the case of NPPD, Cooper Nuclear Station at a nominal 800 MW is the largest generator on the system. NPPD also serves Nucor Steel which can produce major load swings as it operates an electric arc furnace. In the past NPPD worked with WAPA to assist with load following, but WAPA's resources now operate in the SPP market and may not be available to assist NPPD should Nebraska leave SPP.

SPP's large electric system footprint promotes efficiency through generation resource sharing. The integrated market is designed so that an area with low cost surplus electricity can benefit by selling excess generation into the market which benefits other utilities. This allows SPP to see the entire footprint when it comes to dispatching electricity as efficiently and cost effectively as possible. The market to sell and buy from would shrink significantly if Nebraska leaves SPP.
SPP offers diverse power products that can be used to hedge against price risks, foster stable prices, and provides price transparency. Nebraska members leaving SPP would have fewer tools to help mitigate these types of risk.

Fourth, there has been a significant transformation of the generation/energy mix in Nebraska. If the Nebraska utilities were required to go back to three balancing authorities or even operate a single consolidated one for Nebraska, there would be challenges reliably balancing the load with the amount of increased intermittent generation and the reduction in baseload resources which has occurred over the past several years for economic and environmental reasons.

Fifth, it is highly likely the Nebraska utilities would need to add staff to establish balancing authority responsibilities and could be required to add generation/transmission facilities to reliably balance loads in the state.

SPP currently provides Reliability Coordinator and Planning Coordinator services to the Nebraska members. These services are critical to maintain compliance with North American Electric Reliability Corporation (NERC) reliability standards which are mandated by Federal Energy Regulatory Commission (FERC). If the Nebraska members would leave SPP, we would either have to contract with another established Regional Transmission Organization (RTO) (i.e. MISO) to provide these services or develop the expertise in-house which would require substantial investment in new facilities and labor force along with future long term development needs. These services are usually bundled under an existing RTO, so MISO would force the Nebraska entities to join as a full new members which would mean that Nebraska entities would pay for the new MISO RTO on top of the prior exit fees due to SPP, which would be a substantial increase to current ratepayer costs.

Sixth, there is a question what relationship, if any, Nebraska's utilities would have with the SPP market which provides a round-the-clock opportunity to buy and sell energy. This has benefitted the utilities and their customers both as buyers and sellers, Nebraska's utilities have been net sellers into the SPP integrated market since its inception and have produced additional revenues for the benefit of their Nebraska customers. On the flip side, when Nebraska utilities have either scheduled or unscheduled outages at their facilities, the SPP market has been a cost-effective source of replacement energy.

Seventh, the future long term transmission expansion plans for Nebraska entities will be directly impacted by plans developed at SPP. Currently the Nebraska members have important influences through the SPP planning processes and Generator Interconnection processes. By leaving SPP, the Nebraska entities will have very little ability to influence those future developments and we will be forced to constantly address significant new transfers which flow through the Nebraska region due to the interconnected nature of the bulk transmission system. These interconnection impacts will also be evident if the SPP RTO expands into the Western interconnection as two existing DC ties are adjacent to existing NPPD transmission facilities in western Nebraska.

In conclusion, while it is not possible to quantify the full financial and operational impacts of Nebraska's utilities withdrawing from SPP, it is apparent that any such action would have significant impacts.

ATTACHMENT 2

ATTACHMENT 2

Southwest Power Pool Membership – Exit Process; Onboarding and Offboarding

There are several levels of involvement in SPP, such as Member, Market Participant – Asset Owner, Market Participant – Financial Only, Meter Agent, Transmission Customer, and Transmission Owner. Each category may involve dozens of unique service agreements, and each may have unique costs and steps of exiting. Many of the Nebraska Members, such as OPPD, NPPD, LES, and MEAN have unique contracts with SPP per each level of membership. For example, being an asset owner, financial owner, and Transmission owner or even just a customer may have special steps.

Please see the following information on each role:

Member
Entitles your company to voting privileges and decision-making rights as a participant in select organizational groups. Membership may be stand-alone or in conjunction with other registration types.

- Voting rights: Markets and Operations Policy Committee and Membership Committee
- Annual fee
- Withdrawal obligation (exit fee)

Market Participant - Asset Owner
An asset owner with load and/or generation physically or pseudo-tied within the SPP balancing authority.

- Direct ICCP connection required, either MP or through a third party.
- Meter data required
- Virtual market participation
- Bilateral settlement schedules capability

Market Participant - Financial Only
A non-asset owner who wants to participate in our markets through virtual energy offers, virtual energy bids, TCR auctions, and/or bilateral settlement schedules.

- Virtual market participation
- Bilateral settlement schedules capability

Transmission Customer
Transmission customer status allows an entity to do business with SPP on the Open Access Same-Time Information System.

- TCR market participation starting the month after the implementation date
- Tagging/scheduling capability

Transmission Owner
An entity that owns/maintains transmission facilities, each member who facilitates (whole or in part) make up the transmission system and had executed a membership agreement as a TO. TOs that are not regulated by the commission shall not become subject to commission regulation by virtue of their status as TOs under this tariff, provided that service over their facilities classified as transmission and covered by the tariff shall be subject to commission regulation.

- Owns/maintains transmission facilities in SPP
- Must also be a member of SPP

Meter Agent
Entity providing meter for a registered asset.

- Submit meter data via XML file

The following summarizes the withdrawal requirements and process of the SPP Membership Agreement followed by a little more detail from the SPP Membership Agreement:

1. SPP member notice of intent to withdraw – at least 24 months to intended termination date.
    a. Various related membership agreements (e.g., market participant agreement, meter agent agreement, transmission agreements, etc.) have processes with various timelines, but terminating those agreements should occur within the 24-month notice of termination period.
    b. Network Integration Transmission Service Agreements (NITSA) terminate by their own terms and cannot be terminated early.

2. Payment of a withdrawal fee of either $50,000 for non-load-serving entities or $150,000 for load-serving entities.

3. Calculation and payment of exit fees:
    a. Member's unpaid annual membership fee;
    b. Member's unpaid dues, assessments and other membership fees;
    c. Member's share of entire principal amounts of all SPP Financial Obligations, including, but not limited to:
        i. Debts under all mortgages, loans, bonds, borrowings, credit lines, etc.;
        ii. All payment obligations under equipment, financing or capital leases, real estate and office leases, consulting contracts, etc.;
        iii. Any costs, expenses or liabilities incurred by SPP directly due to the termination; and
        iv. Credit for Member's share of all interest that will become due with respect to all interest bearing financial obligations that will mature after the termination date.
        v. In addition, a Member who is a Transmission Owner remains responsible for all financial obligations incurred and costs allocated to its load for transmission facilities approved prior to the termination date.

According to the Southwest Power Pool Membership Agreement under 4.1, there are Events of Termination and Partial Termination for membership:

A. "termination " shall mean cessation of Membership, voluntary or involuntary, or a termination of the is agreement for any reasons including the following:

a. Member voluntarily withdraws from membership under Section 4.0 or 5.0 of the Governing Document Tariff,

b. An involuntary termination of membership occurs pursuant to Section 6.0 of this agreement;

c. Member withdraws for membership or terminates this Agreement to comply with the terms of any applicable law or regulation;

d. A withdrawal from membership or termination of this Agreement is ordered by any court or administrative agency of competent jurisdiction; SPP reserves its rights but is not obligated, to maintain before such court or administratively agency, or on nay appeal, the FEC has preemptive jurisdiction.

e. A material breach or repudiation of this Agreement, in the discretion of the non-breaching or non-repudiating party;

f. The liquidation of dissolution of SPP, unless a third party has assumed the rights and obligation of SPP under this Agreement consistent with Section 8.2 and has reasonably demonstrated capability to perform SPP's obligations under this Agreement;

g. An agreement between SPP and the Member to terminate this Agreement.

A "partial Termination " occurs upon a Member's voluntary removal of a portion of its transmission facility or customers from the SPP Region, including, by way of example and limitation, sale or a part of the Member's distribution or transmission network or transfer to another service provider of a portion of its retail load.

4.2.1 of the Member Agreement outlines the steps for just Membership Voluntary withdrawal. A Member may withdraw voluntarily provided that it has given written notice to the President of its intent to withdraw. Notice of intent to withdraw must state a proposed date forth the withdrawal and be deliver to the President no less than twenty-four (24) months prior to such date.

In each Agreement a Member submitting a written notice of its intent to withdraw must simultaneously submit a cash withdrawal deposit to SPP, as set forth in the Agreement. If the cost exceeds the withdrawal deposit, the additional amount shall in included in the invoice SPP provides to the Member.

After the invoice for the Membership termination, the Member shall provide payment to SPP within thirty (30) days of receipt of the invoice. If the withdrawal deposit exceeds the costs of processing the member's withdrawal and or reintegration, SPP shall refund the difference to the Member.

The Membership Agreement then goes on to state the Voluntary Withdrawal if the withdrawing Member is a Transmission Owner subject to FERC jurisdiction, the Termination Date shall be the later of

(i) the proposed date specified in the withdrawal notice or the date agreed by SPP,
(ii) the effective date, of any, set by the FERC order approving the withdrawal, or
(iii) the date that such FERC order is no longer subject to review by a court of competent jurisdiction.

A FERC filing would also be required for a withdrawing Transmission Owner which could take up to a year or longer.

Lastly, a member may terminate this agreement with less than the required twenty-four (24) months' notice, in the event that the Federal or state law governing Member changes, or any provision of this Agreement, the provision of SPP's OATT or SPP's Bylaws are changed or modified in a manner that causes a conflict with the Member's Federal or state law, regulations, or their schedules, and an internal dispute resolution process is unable to resolve such conflict. In such event, Member and SPP shall meet and confer to facilitate the withdrawal as soon as practicable as necessary to ensure compliance with Federal or State law. The member is also responsible for all final settlements and any resettlements for up to 365 days from the notice of termination of one's Market Participant Agreement.

In general, the membership agreement has a 24-month written notice requirement with an exit fee based upon the certain asset and debt criteria.

APPENDIX NO. 5

SPP LR136 Responses to Committee Questions

October 27, 2021

Cecember 13, 2021

October 27, 2021

Senator Bruce L. Bostelman
Chair, Natural Resources Committee
State Capitol
P.O. Box 94604
Lincoln, Nebraska 68509-4604

Sent Via Electronic Mail: bbostelman@leg.ne.gov

RE: LR136, Evaluating the Impact and Circumstances Surrounding the Electrical Outages in February, 2021.

Dear Senator Bostelman,

Thank you for your letter dated October 20, 2021 ("October 20th Letter"). Southwest Power Pool, Inc. ("SPP") appreciates the opportunity to respond to the questions posed in the October 20th Letter regarding the operation of the SPP transmission system during the February 4, 2021, through February 20, 2021, winter weather event ("February 2021 Weather Event").

<u>Responses to Questions from your October 20th Letter:</u>

Question 1: Has SPP determined that during the extreme loading conditions (in the footprint and/or balancing authorities were appropriate) and when dispatchable resource supplies and load matching are close enough that curtailing intermittent resources is necessary to relieve congestion and maintain inertia? Why or why not?

Response 1: The SPP Integrated Marketplace ("SPP IM") allows for all resources to be considered when re-dispatch of those resources is needed to ensure transmission congestion is mitigated. The SPP IM uses a security constrained, least-cost dispatch algorithm that ensures transmission congestion is managed both reliably and economically. At times, intermittent resource output may be reduced to maintain appropriate levels of transmission loading based on both economics and impact on transmission congestion.

The SPP Balancing Authority (BA) performs market studies several days in advance of and leading into, as well as throughout, the operating day. These studies are used to ensure that adequate resources are committed to serve load, provide regulation, maintain contingency reserves, and supply any scheduled exports. In these studies, the forecasted values of individual intermittent resources are often assumed to be the maximum dispatch level for those resources. These studies attempt to assess and mitigate projected transmission system congestion using dispatchable resources including intermittent resources.

As studies are required to prioritize energy needs and transmission system constraints, additional resources may be recommended for commitment. In the event that market studies are unable to mitigate transmission system constraints due to a lack of available dispatch capability on resources or due to a requirement to prioritize energy needs above transmission system congestion, as was often the case during the February 2021 Weather Event, additional actions may be taken by the Reliability Coordinator in order to maintain system reliability. These actions may include the manual re-dispatch of resources in the form of issuance of Out-Of-Merit-Energy (OOME) orders which dispatches units out of economic merit order to be able to meet reliability needs. During the February 2021 Weather Event, SPP experienced heightened transmission system congestion which was mitigated in part by market re-dispatch of resources, including intermittent resources, as well as by manual re-dispatch instructions via OOME.

SPP currently places no system inertia requirements on generating resources. However, system inertia is calculated and monitored based on the results of studies performed in advance of the operating day to ensure that inertia levels stay above SPP's estimated minimum contribution. At this time, SPP estimates that its current system inertia is well above the calculated SPP minimum contribution needed to support the interconnection. This minimum was determined in 2019-2020 by the SPP Holistic Integrated Tariff Team (HITT) as part of the R1b initiative to study all reliability services required by the interconnection. https://www.spp.org/Documents/62352/HITT R1 Reports.zip

Following the comprehensive review of the February 2021 Weather Event, SPP and its members have established the Improved Reliability Availability Task Force (IRATF). This Task Force is chaired by a member of the Regional State Committee and is composed of SPP staff and members of the following SPP working groups: Cost Allocation Working Group, Supply Adequacy Working Group, Operating Reliability Working Group and the Market Working Group. The IRATF is responsible for addressing the Tier 1 Fuel Assurance and Resource Planning and Availability recommendations identified in the comprehensive review. Various BA resource adequacy measures will be addressed, one of which is required reliability services to the BA, including inertia.

Question 2: Has SPP studied the maximum load that can be served with Natural Gas in the SPP footprint and still serve home heating, electric generation, industry, etc. during extreme cold conditions?

a. If so, is there a plan to order a moratorium on further renewable utility-scale interconnections when that point is reached?

Response 2: Gas availability has a great impact on the maximum load that can be served by gas generators, and SPP can only assume the accredited capacity of gas generators will be available. SPP does not have the information needed to perform a study to determine the energy loads (electric generation, home heating, industry, etc.) that can be served by natural gas in the SPP footprint. This type of study requires detailed information of gas demand for home heating, gas demand of industrial customers, and power plants as well as the available gas supply to the area. That is information that is not available to SPP, and SPP does not have authority to request that data. However, a number of efforts, including the IRATF, are underway that are designed to improve SPP's ability to assess natural gas availability and its impact, as well as the impact of other fuels, on generation in the footprint.

SPP has processes and procedures in which it is able to accredit its gas-fired generation capacity. The available capacity from gas fired generation was reported at over 29,500MW for the 2021 summer season. As part of the initiatives identified in the investigation into the February 2021 Weather Event, SPP will continue to review the appropriateness of the current methodology for accrediting gas-fired and other types of resources. Some of these initiatives identified had started prior to the February 2021 Weather Event, including processes for determining the capacity value of resources by taking into account "performance based accreditation" in which the accreditation value assigned to a resource is based on how well the resource has performed in past events.

The IRATF is also undertaking a "Fuel Assurance" initiative in which a more in-depth review of gas-fired generator outage causes is being performed. If it is determined that the gas-fired generators were out of service due to a lack of fuel availability, then additional analysis and review may be warranted to determine if there are measures that can be taken by the electric industry to improve gas availability.

SPP also participates in activities that take place on a national level at the North American Electric Reliability Corporation (NERC) and the North American Energy Standards Board (NAESB). Following previous winter events that impacted the electric industry, these organizations initiated efforts to improve electric and gas winterization, communication, and coordination. Most recently, SPP led industry's effort in the development of the NERC Cold Weather Reliability Standards approved by the Federal Energy Regulatory Commission (FERC) in August. These standards "require generators to implement plans to prepare for cold weather and require the exchange of certain generator cold weather operating parameters that would help enhance situational awareness in the operational planning and Real-time operations timeframes." The FERC/NERC inquiry into the February 2021 Weather Event recommended the need for NERC reliability standards to go beyond these. NAESB also re-activated its Gas Electric Harmonization Committee in June. This committee solicited comments regarding the potential need for additional harmonization efforts between gas and electric standards. There were 31 proposals or considerations raised, and the committee continues to discuss how best to address these.

SPP does not have any plans to order a moratorium on further renewable utility-scale interconnections, nor does it or any other Independent System Operator (ISO) or Regional Transmission Organization (RTO) have the authority to do so. As a FERC jurisdictional RTO, SPP is required to provide non-discriminatory open access for any interconnection customers requesting interconnection to SPP. To ensure that SPP is accurately capturing the reliability value of the renewable generating resources, SPP uses the Effective Load Carrying Capability (ELCC) methodology for determining the capacity value of renewable generating resources. ELCC studies have shown that the accreditation percentage of renewable resources will decrease as the penetration of the resources increase on the system. However, even though the accreditation decreases, the amount of capacity will generally continue to increase, just at slower levels. This level of capacity may or may not increase at the same pace regardless of how much thermal conventional generation is on the system. SPP continues to analyze future penetrations of renewable generation as well as future levels of retirements of thermal conventional generation to determine the impact of either factor. Energy storage resources, which need other resources to charge, will also have their capacity value determined, in part, by the presence and amount of those other resources.

Question 3: Who are the "non-asset owning, and financial-only market participants?" What facilities or utilities are they participating in the market with?

a. Did they profit from the February freeze event?

Response 3: SPP refers to financial-only market participants ("FOMP") as those entities who do not own or represent physical assets used to generate, transmit, or distribute energy and who speculate on pricing differentials in its financial-only markets. A full list of current market participants, including FOMPs, can be found on SPP's website: https://www.spp.org/about-us/members-market-participants/.

SPP administers two financial-only market products traded in the SPP IM: virtual energy and transmission congestion rights transactions. While both products can be utilized to provide financial hedging against real-time energy and transmission price fluctuations, FOMPs attempt to profit from pricing differentials. All of the energy markets administered by the other ISOs and RTOs and regulated by FERC contain similar financial-only products. FERC believes these products help achieve pricing efficiency and provide liquidity in energy markets.

In its Report on February 2021 Weather Event, SPP's Market Monitoring Unit ("MMU") estimated that virtual energy transactions "made just under $400 million during [the February 2021 Weather Event] period." The MMU is recommending "a study to assess the effectiveness of virtual transactions during the winter weather event and identify any potential lessons learned or recommendations going forward." The MMU's full report can be found here:
https://www.spp.org/documents/64975/spp_mmu_winter_weather_report_2021.pdf.

SPP appreciates the opportunity to respond to your questions and looks forward to presenting before your committee on October 29, 2021. Please contact me if there is further information that you may need.

Sincerely,

Lanny Nickell

Lanny Nickell
Executive Vice President &
Chief Operating Officer
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223
Tel: (501) 614-3232
lnickell@spp.org

December 13, 2021

Senator Bruce L. Bostelman
Chair, Natural Resources Committee
State Capitol
P.O. Box 94604
Lincoln, Nebraska 68509-4604

Sent Via Electronic Mail: bbostelman@leg.ne.gov; kbohlmeyer@leg.ne.gov

RE: LR136, Evaluating the Impact and Circumstances Surrounding the Electrical Outages in February 2021

Dear Senator Bostelman:

Thank you for the opportunity to appear before the Natural Resources Committee on October 29, 2021, to testify at the hearing on LR136, Evaluating the Impact and Circumstances Surrounding the Electrical Outages in February 2021.

Southwest Power Pool, Inc. (SPP) also appreciates the opportunity to respond to the post-hearing questions submitted by Members of the Committee and included in your letter dated November 19, 2021 ("November 19th Letter").

Responses to Questions from your November 19th Letter:

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    - Objectives of RPA 1: to quantify the minimum reliability attributes needed from SPP's resource mix to reliably operate the SPP Balancing Authority (BA) now and in the future; to develop a framework for the periodic assessment of the ability of the SPP BA fleet of resources to adequately provide these attributes; and to identify the required changes to incentives, policies and requirements necessary to secure these attributes.
- RPA 2 (Tier 1): Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives that ensure sufficient resources will be available during normal and extreme conditions.

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Through SPP's Comprehensive Roadmap Process, all Tier 2 and 3 initiatives have been assigned to appropriate SPP stakeholder groups where they will be addressed according to stakeholder prioritization and SPP scheduling. An inventory and high-level status of all 2021 winter weather event initiatives can be found at: https://spp.org/spp-documents-filings/?id=206880.

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a. The SPP website claims to have over 90,000 MW of capacity of which over 28,000 are utility scale wind. Simple math and rounding indicate 90-30=60,000 MW somewhere in the SPP footprint. The balance should have easily covered the load even during peak conditions. Why didn't it?

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SPP also performs a detailed design assessment of its UFLS program every five years to ensure it meets NERC Reliability Standard PRC-006 requirements. This assessment simulates the loss of 25% of the generation across the SPP Planning Coordinator (PC) footprint to assess the arrest of the frequency by shedding load based on the 10%/10%/10% reduction at the respective set points of 59.3 Hz, 59.0 Hz and 58.7 Hz. This ULFS Design Assessment was last performed in 2019. The 2019 ULFS Design Assessment showed that the 25% generation-to-load imbalance was arrested by the shedding of 21.1% of island load. Minimum bus frequency identified by the assessment was 58.06 Hz, and the maximum frequency was 60.3 Hz. The results of this assessment met NERC Reliability Standard PRC-006 requirements and reaffirmed the adequacy of the load shed increments of a minimum of 10% of their load at each of the frequency set points of 59.3 Hz, 59.0 Hz and 58.7 Hz, totaling a 30% reduction in load.

Thank you again for allowing me the opportunity to deliver my testimony before the Committee and to respond to Members' post-hearing questions. Please contact me if there is further information that you may need.

Sincerely,

Lanny Nickell
Executive Vice President &
Chief Operating Officer
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223
Tel: (501) 614-3232
lnickell@spp.org

Southwest Power Pool

Working together to responsibly and economically keep the lights on today and in the future.

December 13, 2021

Senator Bruce L. Bostelman
Chair, Natural Resources Committee
State Capitol
P.O. Box 94604
Lincoln, Nebraska 68509-4604

Sent Via Electronic Mail: bbostelman@leg.ne.gov; kbohlmeyer@leg.ne.gov

RE: LR136, Evaluating the Impact and Circumstances Surrounding the Electrical Outages in February 2021

Dear Senator Bostelman:

Thank you for the opportunity to appear before the Natural Resources Committee on October 29, 2021, to testify at the hearing on LR136, Evaluating the Impact and Circumstances Surrounding the Electrical Outages in February 2021.

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APPENDIX NO. 6

"A Comprehensive Review Response"

Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Event, SPP
July 19, 2021

(108 pages)

Available in the Office of Natural Resources Committee

6

SPP Southwest Power Pool

A COMPREHENSIVE REVIEW OF SOUTHWEST POWER POOL'S RESPONSE TO THE FEBRUARY 2021 WINTER STORM

ANALYSIS AND RECOMMENDATIONS

By Southwest Power Pool

Published on July 19, 2021

Version 1.0

APPENDIX NO. 6a

SPP REPORT: FEBRUARY 2021 WINTER STORM EVENT & SHORT RECAP

MARCH 2, 2021

Available in office of Natural Resources Committee

6A

SPP Southwest Power Pool

FEBRUARY 2021 WINTER STORM EVENT

LANNY NICKELL
EXECUTIVE VP & CHIEF OPERATING OFFICER
SPP BOARD OF DIRECTORS
MARCH 2, 2021

Helping our members work together to keep the lights on... today and in the future.

6A

SPP Southwest Power Pool

SHORT RECAP OF FEB 2021 WINTER EVENT

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool

SPPorg

southwest-power-pool

APPENDIX NO. 7

A Comprehensive Review of SPP Communications during the February 2021 Winter Storm, Analysis and Recommendations July 19, 2021

(61 pages)

Available in the Office of Natural Resources Committee

7

A COMPREHENSIVE REVIEW OF SPP COMMUNICATIONS DURING THE FEBRUARY 2021 WINTER STORM

ANALYSIS AND RECOMMENDATIONS

By Southwest Power Pool

Published on July 7, 2021

Version 1.0

APPENDIX NO. 7a

SPP Report on February 2021 Winter Weather Event – Market monitoring

July 14, 2021

64 pages -Available in

Legislature's Natural Resource office

7A

SPP Southwest Power Pool
MARKET MONITORING UNIT

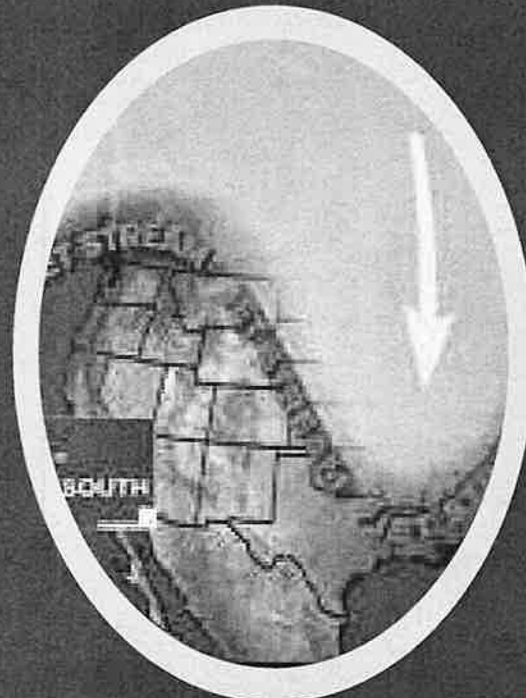
REPORT ON FEBRUARY 2021 WINTER WEATHER EVENT

Published on July 14, 2021

APPENDIX NO. 8

LES February 2021
Extreme Weather Lessons Learned
and Corrective Actions
September 13, 2021

Operations and Power Supply Committee



Extreme Weather Lessons Learned and Corrective Actions

By Tom Davlin

September 13, 2021

Lincoln Electric System

LES.com

8

Post Event Action Items

- **After the February cold weather event all impacted groups met to review issues encountered during the event**
- **Meetings resulted in 35 Action Items and additional Lessons Learned**
- **Action Items addressed to date:**
  - Generating Sites: 9 of 15 items resolved, 5 of remaining 6 items to be resolved this year, combustor tuning requires cold temps.
  - DEC: 5 of 6 items addressed, CADF heat tracing item to be completed before winter
  - Environmental: 6 of 8 items resolved, working with LLCHD on 2
  - Marketing: 4 of 7 items resolved, 2 of remaining items will be resolved before winter, 1 item requires coordination with SPP

Key Operational Issues
Generating Sites

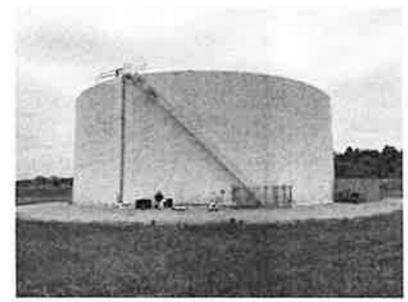
1. **Frozen pipes/failed heat tracing**
   1. Developed inventory of sites' heat tracing installations
   2. Evaluating adding heat tracing monitoring panels
   3. Creating automated work tickets to verify heat tracing systems are operational going into the winter season
2. **Tank roof/side wall rupture due to frozen air vent**
   1. Installed "frostless" vents on 2 TBGS storage tanks and verified tanks Rokeby and J St tanks have suitable vents

Key Operational Issues
Generating Sites

3. Fuel Oil Deliveries

1. Held discussions with fuel oil delivery vendors on getting priority service during extreme weather events
    1. **Discussions with Magellan pipeline operator included an expedited process for getting pipeline fuel oil deliveries to Rokeby**
    2. **Discussions with fuel oil suppliers on getting expedited tanker deliveries to TBGS and J St not as productive**

Mixed bed bottle



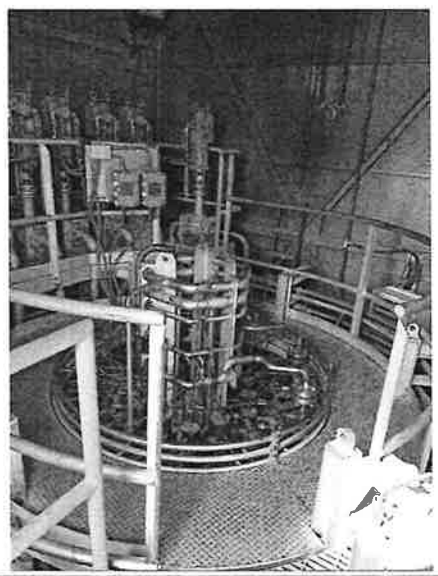
4. De-Ionized Water Production & Deliveries

1. Developed plan for temporary water production at J St
2. Documented procedures for maximizing DI water production at Rokeby

Key Operational Issues
Generating Sites

5. Rokeby 2 & 3 Combustor Pulsation Issue

1. Working with OEM on combustor pulsation issues at low ambient temperatures
2. Wil complete testing this winter and adjust fuel & water staging curves to improve cold weather performance



Key Operational Issues
DEC

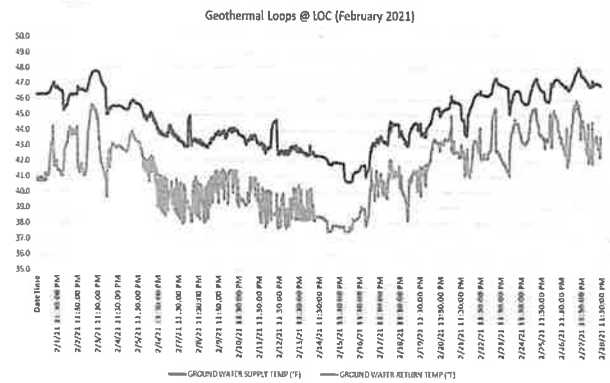
1. **Frozen Fuel Lines**
    1. Identified County Adult Detention Facility emergency generator fuel piping heat tracing need

2. **Fuel oil deliveries**
    1. Held discussions with fuel oil delivery vendors on getting priority service during extreme weather events
        1. **Discussions with Magellan pipeline operator included an expedited process for getting pipeline fuel oil deliveries to Rokeby**
        2. **Discussions with fuel oil suppliers on getting expedited tanker deliveries to DEC facilities not as productive**

Key Operational Issues
DEC

3. Low heating water supply temperature to DEC LES Operations Center customer due to excessive well field cooling

1. Working with customer on DEC and customer operational adjustments during extreme cold weather



4. High cooling water supply issue to DEC West Hay Market customer due to cooling tower freeze up

1. Completed control logic changes to address cooling tower operation issues during extreme cold weather

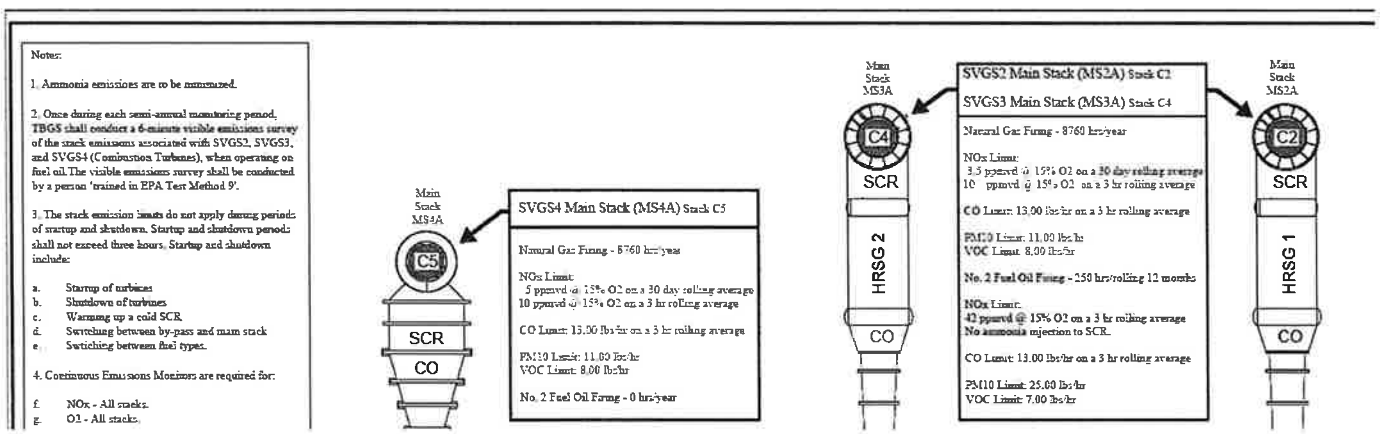
Environmental Compliance Issues

1. **Address air permit emissions exceedances due to water injection system failures**
    1. Water Injection System outages qualify for an affirmative defense of unexpected malfunction and shouldn't result in notice of violation
2. **Request for variance for Rokeby 3 Carbon Monoxide emission limits**
    1. Sent a request to the Lincoln Lancaster County Health Dept. asking to exempt the 75 tons of CO generated by Rokeby 3 during the cold weather event (fuel oil at low load levels)
        1. Have less than 4 tons of the 99 tons limit available. Emissions calculated on rolling 12 months..
        2. If rejected, the 75 tons from the Polar Vortex will not fall off until January 31, 2022

Environmental Compliance Issues

3. Documentation availability for air emission limits

1. Emission limit documentation has been sent to generating sites



4. Nitrogen Oxide emissions allowances inventory

1. We had previously retained a small surplus of allowances, and should not have issues covering our generation.

Marketing Action Items

1. **SPP Day Ahead commitments for wind resources**
    1. SPP committed wind at their Emergency Max levels instead of at the forecasted generation levels
2. **SPP Dispatch Target Adjustment**
    1. Real time dispatch adjustments were not able to settle correctly. SPP evaluating using existing Out of Merit Energy logic.
    2. Alarmed SCADA Dispatch Target Adjustment notices
3. **Generator Operator Reporting Requirements**
    1. Worked with LES Compliance to update Event Reporting Operating Plan to include reporting timeline and responsibilities.
4. **Daily Natural Gas Nominations**
    1. Need to address differences in gas and electric nomination times

Marketing Lessons Learned

1. **Submitting Energy Offers Over $1000/MWh**
    1. Offers over $1K need Market Monitor Unit approval prior to Day Ahead Market close
2. **Maintaining Detailed Operator Logs for Future Analysis**
    1. Detailed System Energy Management operator logs were invaluable for settling market disputes and post-mortem analysis.
3. **Using "open line" Teams call for corporate coordination**
    1. This proved invaluable for inter-company communication

Marketing Lessons Learned

4. **Coordination with Environmental Dept**
    1. Having Environmental on the “open line” Teams call was very beneficial
5. **Day Before Day Ahead Reliability Commitments**
    1. These are commitments made ahead of the Day Ahead commitments to address reliability concerns
    2. Changes in costs from time of commitment to unit operation need after the fact approval by Market Monitoring Unit
6. **Control Room Staffing**
    1. Staffing was increased to 2 operators 24/7 to address additional workload during extreme events

Thank you

Questions/Comments?

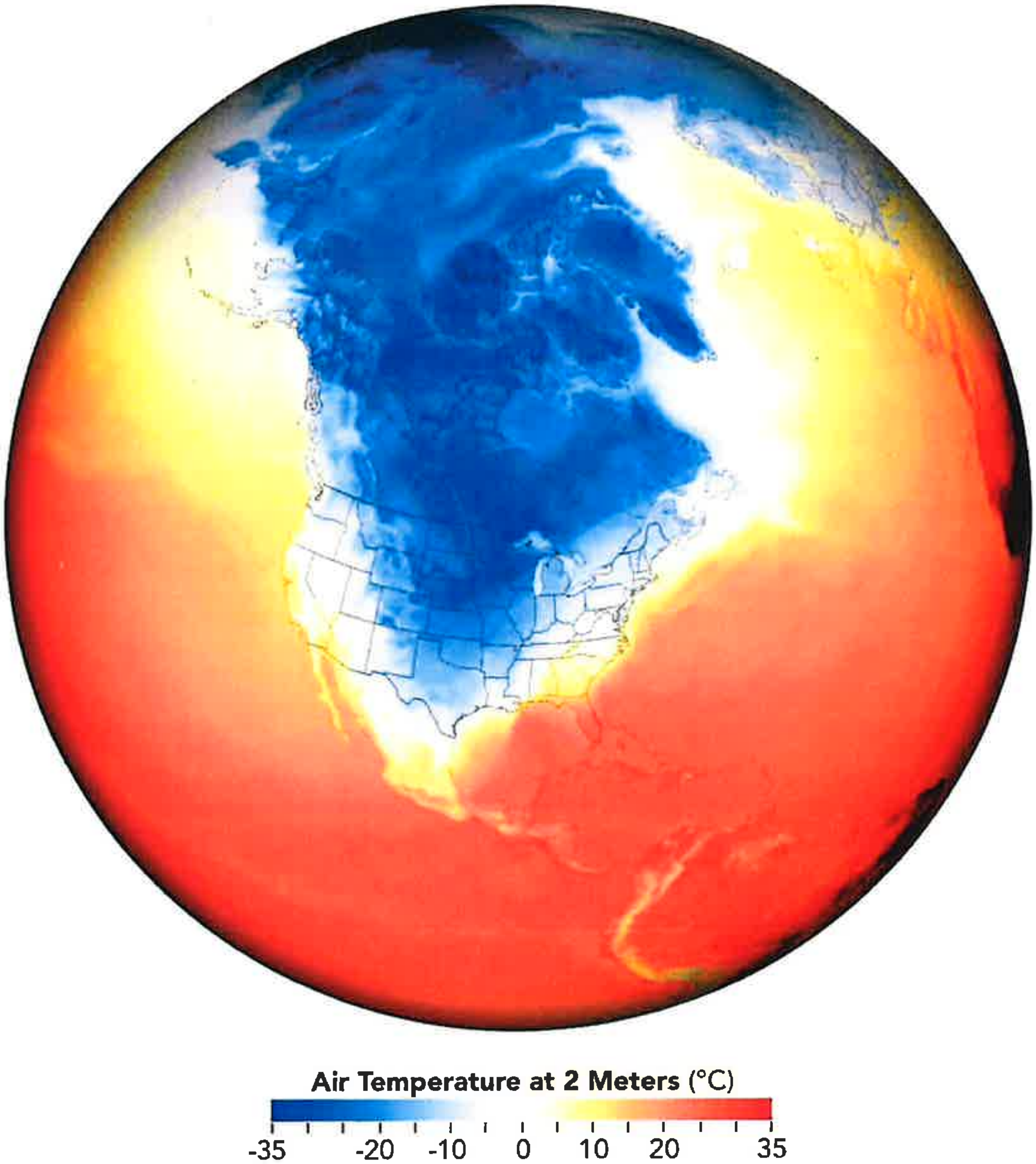
APPENDIX NO. 9

OPPD

The Polar Vortex Load Shedding Event: Lessons Learned

The Polar Vortex Load Shedding Event

February 4 – 20, 2021



NASA. *Extreme winter weather causes U.S. blackouts*. NASA. https://earthobservatory.nasa.gov/images/147941/extreme-winter-weather-causes-us-blackouts.

Event Summary, Lessons Learned, Recommendations for Improvement

Table of Contents

ABOUT OPPD

Mission: To provide affordable, reliable and environmentally sensitive energy services to our customers.

Omaha Public Power District is a publicly owned electric utility that serves an estimated population of 850,000 people, more than any other electric utility in the state. Operating since 1946, the public utility is governed by an elected board of eight directors. While its headquarters is located in Omaha, Neb., OPPD has several other service locations in its 13-county, 5,000-square-mile service area in southeast Nebraska.

OPPD uses baseload power facilities fueled by coal and natural gas, peaking units fueled by natural gas and oil, and renewable energy, including wind, solar, landfill gas, and hydropower.

www.oppd.com

ABOUT SPP

Mission: Working together to responsibly and economically keep the lights on today and in the future.

According to its website information, Southwest Power Pool (SPP) is about more than power. We're about the power of relationships. We work together with our members and other stakeholders to ensure electricity is delivered reliably and affordably to the millions of people living in our multistate service territory.

SPP is a regional transmission organization (RTO): a nonprofit corporation mandated by the Federal Energy Regulatory Commission (FERC) to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its members.

SPP was founded in 1941 when 11 regional power companies pooled their resources to keep Arkansas' Jones Mill powered around the clock in support of critical, national defense needs.

Eight decades later, SPP still reflects our early principles of collaboration in the interest of providing a critical service for the good of our region. Our vision is to lead our industry to a brighter future, delivering the best energy value.

https://spp.org/

Introduction

To the OPPD Community,

I am pleased to deliver this After Action Report examining the Polar Vortex event in February of 2021. The OPPD leadership team requested this review in order to reflect on the event, how we responded, and how we could better respond should future events require a similar response. The men and women of OPPD responded to this unprecedented event with passion, responsibility, and a service attitude exemplifying our core values. I could not be prouder of the effort that went into maintaining the electric grid through this unprecedented event.

In nearly 75 years of OPPD operations, not once had there been an event when customer power was intentionally turned off to save the bulk electric system. We carry the weight of knowing many of our customers use our electricity for life-saving and life-maintaining services, and will always do our utmost to keep the lights on and power flowing. As a customer-owned public utility, our primary obligation is to provide reliable electricity as a fundamental component of modern society.

OPPD employees take great pride in delivering affordable, reliable, environmentally sensitive electricity to our 850,000 customer-owners. When the Southwest Power Pool (SPP) directed us to shed load, it was a very difficult moment for all of us. We have benefited greatly from our membership in SPP, and although a difficult choice was handed to us, we responded as we always do – professionally, immediately, and with the best interests of our customer-owners in mind.

With over 80 employees contributing their experience and reflections to the preparation of this report, I am confident we will continue to learn the necessary lessons that come from such a comprehensive review. We will take positive steps based on the recommendations enclosed herein, so OPPD is better prepared for future emergencies. My deepest hope is that we will never need to shed load again; however, I am confident that if we do, we will be prepared.

Sincerely,

Javier Fernandez

OPPD President and Chief Executive Officer

Polar Vortex Synopsis

While the Omaha area and the central plains have seen cold weather before, it has been some time since the region saw a weather pattern like the one experienced in February, 2021. The National Oceanic and Atmospheric Administration (NOAA) stated the cold wave experienced by the contiguous U.S. was the strongest seen in 30 years.[1] Much of the plains region averaged more than 30 degrees below normal for the period from February 7-21, 2021. The source of much of these cold temperatures was a phenomenon informally known as the "polar vortex" or what climate scientists call an Artic Oscillation (AO). The intensity for this AO at its peak tied for the most extreme February on record since 1950. For context, 99.9% of all days since 1950 had an intensity lower than those seen during the peak of this event. In short, while it gets cold in this region, it almost never gets this cold over such a large area.

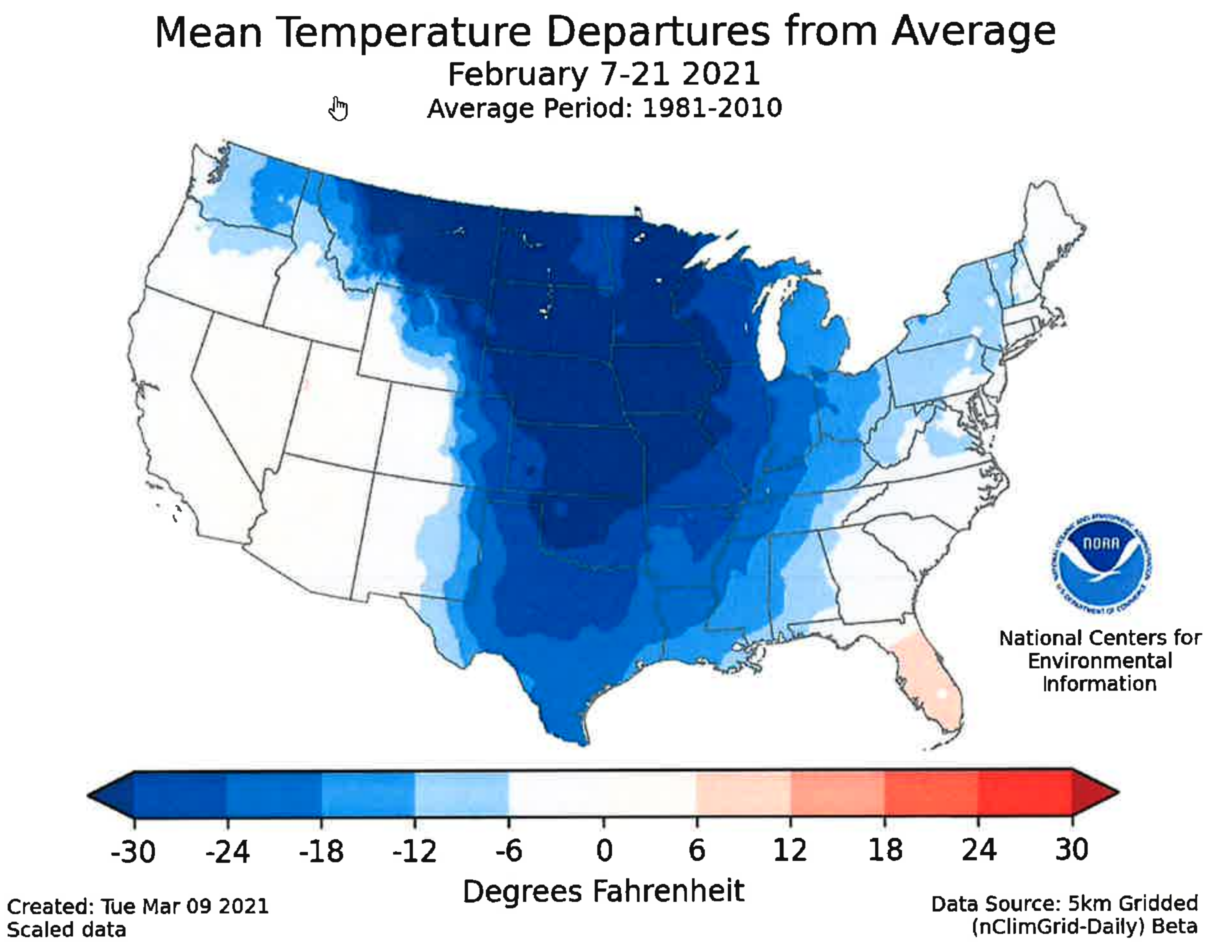


Figure 1 – NOAA NCEI: Mean Temperature Departures from Average Map

[1] https://www.ncdc.noaa.gov/sotc/synoptic/202102

The geographic size, duration, and magnitude of this Polar Vortex put considerable strain on the bulk electric system in the SPP region and neighboring regions, as shown in this map provided by SPP.

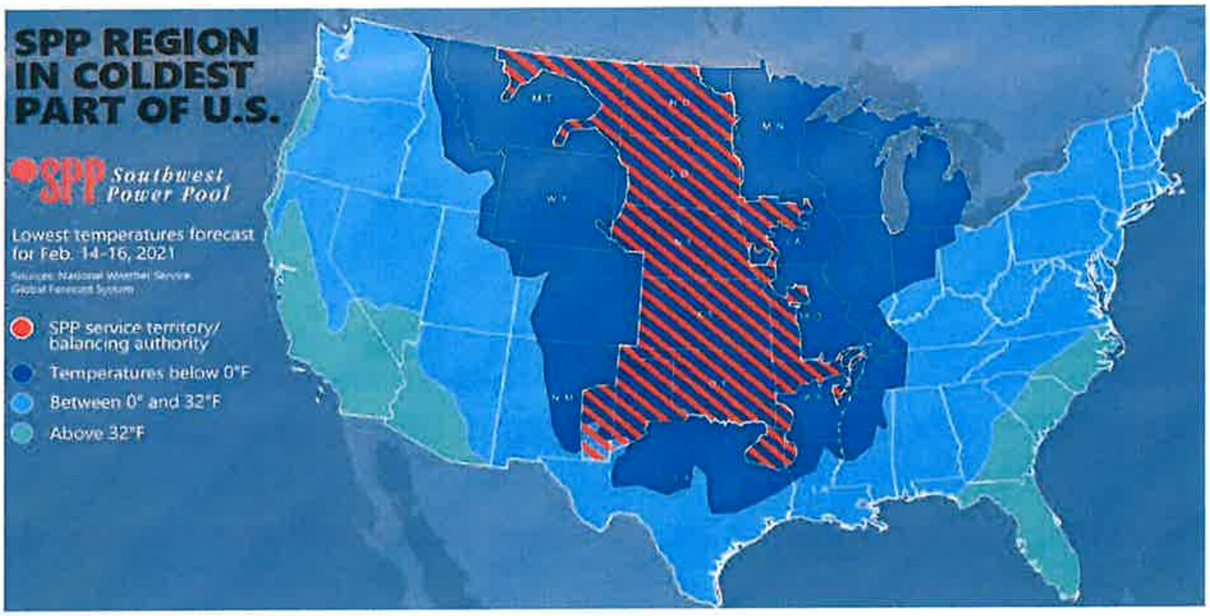


Figure 2 – SPP: Low-Temperature Map

With almost the entire SPP footprint experiencing below-zero temperatures from February 14-16, these temperatures created record setting increased demand for home heating and electricity across the entire highlighted SPP region. SPP's after action report on this event will provide more detail on the reasons for the need to enact load shedding to maintain the stability of the regional bulk electric system. This report will focus on review of OPPD's emergency operating plans and how OPPD locally prepares for and responds to these extreme events. Being a member of SPP and required under the shared regulatory requirements from FERC and NERC to maintain the stability of the bulk electric system, OPPD must have a regionally coordinated operating plan in place to be able to respond without intentional delay when the order to shed load is given. Because this was the first time in OPPD's history that the organization had to enact load shedding, and the first time SPP has requested it, both organizations identified the need to learn and improve. This report will focus on the review of OPPD actions so the organization will be better prepared in the future should shedding again be needed to maintain the bulk electric system.

In order to better understand this event and how the electric grid responded, it is critically important to understand that OPPD is part of a regional networked transmission grid, which interconnects our electric system with our neighbors. Being part of this network provides tremendous reliability and economic benefit to our customer-owners in the form of importing and exporting power within the region, which OPPD has leveraged for many years. The Southwest Power Pool (SPP) is the authority over the region of which OPPD and the rest of the large electric utilities in Nebraska are members. OPPD has representatives on several SPP working groups who have performed deeper dives regarding this event and developed recommendations to the SPP Board of Directors. OPPD's involvement includes the review of reliability operations, resource adequacy, transmission planning, market operations and the Comprehensive Review Steering Committee. These recommendation were included in the final report delivered to the SPP Board of Directors at their July 2021 SPP Board

Meeting. OPPD will continue to collaborate with SPP through the various working groups to ensure that SPP's recommendations are implemented in a timely and efficient manner.

It should be noted that OPPD's local electric system performed well during this polar vortex event as evident in the availability of our local power generation and delivery system to meet our customers' needs during the days in which SPP requested load shedding across its entire footprint. However, the combination of increased regional electric demand coupled with reduced availability of power generation in the overall SPP region led to the call by SPP for regional load shedding in order to maintain stability of the reigonal grid. The combination of each SPP member's local after action reviews along with the coordinated SPP regional after action review of this historic event will better prepare us indivually and collectively for future weather events.

Key Takeaways

This extreme event underscores the stresses that come with providing reliable energy despite the most challenging of circumstances. As OPPD looks to improve upon what it can control in this event, below are the key takeaways that were identified.

1. More accessible, individualized, and timely communication is critical to our customers during an energy emergency event and OPPD will improve to meet our customer-owner's communications needs.
2. OPPD's emergency event plan should be enhanced and made more robust to better support grid reliability during extreme events.
3. Given the increased financial risk of a more volatile and interconnected energy market, OPPD should review and consider expansion of its energy and fuel risk mitigation options to reduce the potential impact from future extreme events.
4. OPPD should review customer demand for and consider expanding its customer products and services to increase the usage and flexibility of self-generation and curtailment programs to minimize customer impact during extreme events.
5. OPPD's membership in SPP is critical to our organization's ability to meet our strategic goals and support the delivery of reliable energy during local emergency events (e.g. floods). OPPD should continue to extract value from its SPP membership and leverage our expertise and influence in the SPP stakeholder process to enact positive changes to the benefit of our customers

Recommendations & Prioritization

Recommendations derived from the After Action Review were presented and accepted by OPPD Senior Management and reviewed by the OPPD Board of Directors on June 15, 2021.

Subsequently, each recommendation was evaluated and scored based on the impact to each of the 15 OPPD Strategic Directives, the size of the project, and prioritized by tier for implementation. The evaluation and scores were reviewed and approved by OPPD Senior Management.

The graphic below depicts the prioritization tiers and related definition:

TIER 1

- Recommended actions, policies, or assessments deemed necessary and a priority to avoid significant reliability, financial, operational, compliance or reputational risks.
- These recommendations are expected to mitigate the impact of future extreme weather events.

TIER 2

- Recommended actions, policies, or assessments deemed necessary to minimize the risk of significant reliability, financial, operational, compliance or reputational consequences associated with extreme weather events.
- These recommendations are expected to significantly improve OPPD's response to extreme weather events.

TIER 3

- Recommended actions, policies, or assessments to improve OPPD's response, communications, and customer-owner perception during extreme weather events.
- The work associated with these recommendations should be prioritized for implementation along with other organizational initiatives.

TIER 1 Recommendations

Technology Recommendation 1

Develop or acquire technology tools to better serve our employees and customer-owners with the ability to efficiently and effectively communicate information. (i.e. Advanced Metering Infrastructure (AMI), Customer Relationship Management (CRM), Geographic Information System (GIS), and a more granular power outage map).

Having additional tools to better manage customer data and also have the capability to load shed each meter individually instead of at the circuit level would allow OPPD greater flexibility in responding to load-shedding orders while also responding to individual customer needs.

Enterprise-Wide Recommendation 1

Enhance OPPD's blueprint to improve OPPD's resilience to extreme weather and/or extended duration reliability events; including, at a minimum (in no particular order): a) fuel supply capacity & delivery planning, (fuel strategy), b) inventory management (peaking, plant, service centers), (inventory strategy), c) defining critical customer load and process to keep current, (critical load strategy), d) union contract considerations, (staffing strategy), e) physical location of key personnel, (physical location and facility needs), f) maintenance of plants (peaking), (outage & maintenance strategy), g) retain & validate, periodically, a list of customer contact information for those large customers with their own generation, h) employee fatigue considerations (physical and mental well-being), and i) methods and limits for OPPD facility support (e.g. load shedding).

OPPD's and the SPP regions' generation mix is changing along with the demand on those systems (from extreme weather and evolving customer needs). To continue providing affordable, reliable, and environmentally sensitive energy services to our customers in the future, OPPD needs to evaluate the individual and collective strategies critical to our operations to ensure reliable and resilient energy is provided and processes supporting these strategies are comprehensive and sustainable.

Customer Experience Recommendation 1

Evaluate the priority for a Customer Contact Preference Center to support enhanced customer communications during extreme events.

Extreme events require communication methods with our customers that normal operations do not. Having a tool to manage and maintain customer contact information, and their preferences for communication would allow for improved customer communication during future extreme events. This should include a process that requires OPPD to periodically review and expand the list of customers on our contact list by reaching out to trade associations to ensure small commercial customers are well represented in our contacts.

Enterprise-Wide Recommendation 2

Develop an enterprise definition for resiliency and consider whether additions to SD-9 are needed to ensure appropriate management focus, oversight, and funding.

A resilient utility, one that can withstand disruption and quickly resume normal operations after a significant event, is different conceptually than a reliable utility. Having a clear, enterprise-wide definition will better allow for consistency of evaluating and funding various projects that provide increased resilience to the organization.

Customer Experience Recommendation 2

Evaluate additional customer products and services including rates and information sharing systems needed to provide the organization additional options to manage through emergency events.

Additional distributed energy resources (DER) and demand side management (DSM) via customer products and services would give OPPD additional tools to mitigate potential reliability and financial impacts from extreme events.

TIER 2 Recommendations

Financial Recommendation 1

Evaluate the energy and fuel hedging & trading strategy and risk policy to consider: a) a more diverse portfolio of hedging and insurance options both physical & financial, b) situational (e.g. Energy Emergency Alerts - EEAs) based trading limits, c) emergency price volatility options (ex. out of the money call options), d) cost/benefit of an OPPD natural gas desk, and e) role and scope of Energy Marketing, Trading and Fuels (EMTF) Risk Management to support these efforts.

Evaluating various options to improve OPPD's ability to minimize the financial impacts of extreme events will limit the potential for unforeseen costs to impact rates.

Financial Recommendation 2

Evaluate ways to enhance current curtailment rate offerings to customer-owners (more participation, remove seasonal/weekend/holiday restrictions, additional monitoring and control capability by OPPD).

Requests for energy conservation from our customers involving voluntary demand reduction along with established curtailment programs involving dispatching customer owned generation were effective at reducing the overall demand on the system from what it could have been. However, a majority of OPPD's current curtailment offerings are designed for summer peak-load situations and none of the programs are set up with the required level of advanced OPPD monitoring and control which would be needed to ensure effective response to a Bulk Electric System load shedding event.

These programs should be evaluated for expanded use during non-summer seasons, be equipped with appropriate monitoring and control capability and also identify ways to increase participation in these programs.

Customer Experience Recommendation 3

> *Evaluate enhancements to our public education program to include basic utility operations, purpose and benefits of SPP, regulatory requirements, etc. to be delivered in a variety of methods (i.e. short video clips, newsletters, OPPD.com, etc.).*

During extreme events, customers need to be able to quickly locate and understand the information they are seeking. OPPD should evaluate the various methods and mediums that information is available on and implement improvements.

Enterprise-Wide Recommendation 3

> *Evaluate the necessity to conduct a Climate Vulnerability Assessment.*

Partnering with an outside firm or university to understand the potential and likely climate vulnerabilities for our service territory, state, and region will allow OPPD the best opportunity to deliver on its mission despite a changing climate.

Enterprise-Wide Recommendation 4

> *Develop corporate policy to require cross-functional after action reviews or similar analyses for all significant events, with oversight/management by the Emergency Management team and facilitated by the Continuous Improvement team.*

While many parts of the organization already conduct lessons learned exercises after various events, there is a lack of consistency at the enterprise level after significant events. Requiring this would ensure cross-functional lessons learned are identified and recommendations for improvement implemented in a more formal way.

Enterprise-Wide Recommendation 5

> *Establish an Emergency Response Team (ERT) similar to or modified from the existing Business Continuity structure to provide clarity, transparency and structure to the emergency response efforts.*

Business continuity plans are generally designed for when normal operations are significantly impacted or impossible to perform. The polar vortex event was about performing normal operations during an extreme event. Creating a new process or modifying the existing BCP process to align and support operations at an enterprise level for these types of events will improve the organization's preparation and response to extreme events.

Enterprise-Wide Recommendation 6

> *Refresh, socialize, and test/drill the load shedding, black start, and normal communication channels down plans districtwide, on a regular basis.*

Emergency event plans are routinely drilled by the operational teams who would enact them. Teams in supporting roles are not always involved at the level they should be, which creates the potential for execution gaps. A more expansive program to educate and drill these plans with support functions would better prepare the organization for future extreme events.

Education/Training Recommendation 1

Conduct periodic live simulation training exercises for cross-functional emergency response.

Similar to the above, a more granular recommendation, this recommendation identifies the need for company-wide, live drills of extreme events to ensure organizational readiness.

Communication Recommendation 1

Review/enhance role clarity and authorization levels during emergency events for internal and external communications.

Internal and external communications during extreme events is critical. Reviewing and streamlining existing processes to expedite communications without compromising accuracy would greatly benefit our customer-owners and employees during extreme events. This effort should also confirm that needed skillsets are broadly present amongst the teams responsible for the various roles.

Technology Recommendation 2

Evaluate the need/benefits of Energy Management System (EMS), Outage Management System (OMS), and Customer Information System (ICIS) integrations to support day to day and emergency operations.

These different critical systems support various aspect of managing the reliability of the grid, outage events, and customer information. While there is some integration between these systems, they are not fully tied together in a way that the organization can see the individual customer impacts of opening a breaker on the distribution system. Having these systems fully integrated would provide additional visibility during both day to day and emergency operations.

Communication Recommendation 2

Enhance Communication Plan to include the process for advance district wide/targeted area notification of pending extreme events to improve awareness and any necessary preparation and planning. The process should include thresholds/triggers for level of internal/external communications, in alignment with the emergency event plan and processes.

While specific operating areas were monitoring the potential for grid-related impacts from the polar vortex event in advance, other supporting areas were not made aware of the potential for load shedding until much later in the month, primarily through ad-hoc communication. A more formalized communication plan to alert the organization as needed would improve organization readiness.

Resources Recommendation 1

> *Analyze and develop resource requirements to ensure efficiency while mitigating high market costs and employee fatigue during normal operations and emergency events. Specific considerations: EMTF Risk Management, natural gas traders, meteorologist, two Real Time desk operators, additional external communication surge capacity, etc.*

During the After Action Review interviews, some individuals identified various potential benefits both during normal operations and emergency events of additional staffing resources. Specific staffing recommendations were outside the scope of this review, however it is recommended to have a subject matter expert team perform a more focused review of the items listed above to determine if they are in the best interest of our customer-owners.

TIER 3 Recommendations

Resources Recommendation 2

> *Develop dedicated role(s) for multi-lingual employees for real-time external communication translation and communication planning.*

All customers need to be able to receive critical communications during extreme events to protect their health and safety. Dedicated multi-lingual employees would allow for improved planning and execution of critical event communications to non-English speaking customers.

Education/Training Recommendation 2

> *Evaluate increasing the frequency and use of scenario-based training for FERC Standards of Conduct to improve employee awareness.*

Improved awareness and understanding by impacted employees of what is and isn't allowed when FERC Standards of Conduct are raised or lowered would improve internal communications during extreme events.

Education/Training Recommendation 3

> *Develop specialized training courses for Customer Service representatives to increase knowledge of utility operations.*

Customer Service Representatives are OPPD's front line when responding to customer inquiries during extreme events. Raising the organizational, regional, and industry knowledge of these representatives will improve their ability to confidently respond to the needs and questions of our customer-owners.

Education/Training Recommendation 4

> *Evaluate the need for a real-time energy marketer simulator to support emergency training and readiness of real-time marketers.*

Adding this best practice functionality to the existing energy marketer simulator would improve this area's ability to prepare and respond to extreme events.

Resources Recommendation 3

Enhance Power Purchase Agreements (PPA's) template language and seek to amend, as applicable, existing PPA language to ensure generation ownership, responsibilities, and expectations are clearly defined.

Ensuring performance responsibilities and expectations during extreme events are clear for OPPD's non-owned generation partners is beneficial to our ability to manage through such events.

Communication Recommendation 3

Perform a legal review of any and all applicable laws/statutes on what can/cannot be communicated before/during/after emergency events.

This review would provide OPPD an up-to-date legal basis on what can and cannot be communicated to our customers before, during, and after an extreme event.

Financial Recommendation 3

Develop a financial plan to prioritize and budget for implementation costs associated with the Polar Vortex After Action Review recommendations.

The above recommendations require various levels of resources to implement. Developing a prioritized plan to resource these recommendations will better ensure their implementation and the realization of the anticipated benefits.

Summary of Key Activities

Energy Production & Nuclear Decommissioning (EP&ND)

Preparation & Planning

The EP&ND team did what they do best in the days leading up to the Polar Vortex – they produced power, despite a string of extremely cold days. North Omaha Station 5, which had been on a planned outage for winter maintenance, was brought back online 18 hours ahead of schedule to support the grid during the extreme cold. Both Nebraska City Units 1 and 2 tripped offline during the week prior to the load-shedding event, and staff performed extraordinary measures to ensure both units were back online for the coldest days. The team utilized new drone technology to inspect the known tube leak, rather than wait for the boiler to cool down. This saved hours and provided the ability for the unit to be brought back online ahead of predictions.

The Polar Vortex presented unexpected challenges, which should be considered for future emergency event preparation. Due to a delayed inspection, the Sarpy County Station fuel oil tank was not filled prior to the emergency event. This limited the capacity of the Sarpy County Station even before the event started. In addition, Supply Chain Management was not provided sufficient advanced communications regarding the pending reliability event, which created challenges in receiving necessary equipment and parts for repairs/maintenance.

Response & Execution

Through the coldest days of the Polar Vortex, when SPP requested all available units to be ready and available to respond in a variety of manners, the EP&ND team ensured all generation units were ready and capable to respond. Given the weather, this was not an easy task. Yet the team braved the frigid weather to keep producing energy for our customers. For example, coal-handling crews kept both Nebraska City and North Omaha stockpiles active and accessible throughout the event, whereas other utilities reported suffering from frozen coal stockpiles. Additionally, Operations staff were in place for fuel offloading, working in harsh conditions to keep units running. These teams ultimately operated OPPD generation at a level sufficient to cover the OPPD load.

The following opportunities were identified and should be improved for future emergency events; insufficient stock of heaters for use at the plants to keep all critical systems warm, asset inventory was inaccurate, causing delays on repairing key parts, and communication was inconsistent, leading to some challenges – challenges, in part, exacerbated by the pandemic and inability to gather in person.

Energy Delivery (ED)

Preparation & Planning

The ED team is comprised of multiple critical teams, and each played an important and valuable role in preparing for and responding to the Polar Vortex. The teams were well-trained and demonstrated situational awareness of potential issues and prepared accordingly, for this first-time emergency event. Leaders reviewed the load-shedding plan in advance and began preparing colleagues for the potential event prior to the actual load-shedding requests from SPP. In addition to reviewing the load-shedding plan, the Black-Out Team met regularly after the California outages in the summer of 2020 and have been preparing and training for this kind of scenario.

OPPD's planning and preparation benefited from a well-maintained grid, prepared operators, and up-to-date command and control facilities. The Energy Control Center upgrade provided the necessary capability and capacity for critical communication, situational awareness, and safe operations supporting pandemic protocols. The ED team coordinated well with SPP, SMT, Customer Service, and Corporate Communications.

Response & Execution

Load shedding was executed in accordance with the Load Shedding Plan and the ED team demonstrated agility and flexibility addressing the emergency event. ED quickly responded to SPP requests and dynamically acted to establish additional load-shedding blocks to reduce the chance of areas or customers being repeatedly impacted.

Improvements, for future events, were noted regarding the Energy Management System (EMS) and Outage Management System (OMS) integration. As of today, OPPD does not have the capability to test load shedding down to the user level.

While SPP and internal communication with key stakeholders proved beneficial, customer engagement and communication of the load-shedding plan, throughout the utility, needs improvement.

ED should consider involving cross-functional departments in the review/validation of plan(s) and in maintaining information on critical load. Additionally for consideration, the plan was developed for summer load, and OPPD should evaluate and revise it for seasonal differences as part of the validation of the current plan.

Financial Services (FS)

Preparation & Planning

While all FS staff were ready to support, two departments within the Business Unit – Energy Marketing & Trading (EM&T) and Supply Chain Management (SCM) – played large and important roles in preparing OPPD for the Polar Vortex.

The EM&T team declared OPPD Conservative Operations days before SPP issued their own Conservative Operations directions, which provided key OPPD staff warning and lead time that a significant weather event was approaching. Due to semi-annual black start drills, the real-time energy marketers were prepared leading up to the event.

Unit commitments to SPP reflected unusual activity in the days leading up to the load shedding event, and the Day-Ahead team executed those commitments and related gas acquisition without error under significant time, staffing, and considerable financial pressure.

The Supply Chain Management team expanded the list of fuel oil providers and established contracts quickly, to assist the fuels team in acquiring sufficient fuel oil for the weather event. Supply Chain also acquired a range of key parts and consumables on short notice to keep plants operational.

Opportunities for OPPD to consider going forward include:

- **Risk Policy Refinement:** The Energy Marketing & Trading Risk Policy caps trading activity at a certain level, which then requires additional approvals. These approvals impede trading and may lead to higher prices paid. Energy emergency heightened approval levels would still have appropriate oversight.
- **Gas Supply Capabilities:** With a single gas supplier, OPPD lacked visibility in the gas market for real-time prices.
- **Inventory Control Investment:** Some inventory records were inaccurate, leading to last-minute purchasing and high shipping costs.
- **Communications:** Communication from SCM on material and service needs could have been more effective in establishing next steps, timelines, and setting specific expectations for business partners.

Response & Execution

During the event, EM&T and SCM stepped up and coordinated necessary activities throughout the event. The Day-Ahead team committed large dollar amounts in the market for purchasing both fuel and energy, roughly 100 times normal prices, and acknowledged receiving the full support from SMT leadership and across the organization.

The real-time energy marketers brought in an additional colleague to assist with the many activities, providing enhanced organizational coordination and response. The Transportation & Construction Equipment team members were responsive and effective in maintaining and restarting vehicles and equipment throughout the brutally cold conditions.

Improvements to consider going forward, include:

- Improved real-time communications between SCM staff and users, ensuring clarity on timelines and expectations.
- Notify all wholesale customers with generation and retail customers with behind the meter generation to lessen the overall demand on the grid, which in turn could have saved money.
- Remote work led to several key fuel procurement telephone conversations not being recorded, which is a requirement during emergency events.

Customer Service (CS)

Preparation & Planning

The CS team took a proactive approach in planning and preparing for the Polar Vortex. OPPD communicated and worked with our large commercial & industrial customers to achieve additional voluntary load reductions or self-generation to lessen the demand on the grid. Overall, customers responded positively for these requests to start generation, though a few customers were resistant at first due to environmental concerns.

The communication and coordination within CS and between EM&T, Energy Delivery, and Corporate Communications were noteworthy. Product Development and Marketing, in particular, led the effort to support residential customer communications to ensure messaging was customer-centric.

The collaboration between EM&T and CS facilitated agile, creative, and responsive options to design payments for those customers generating electricity. Additionally, the transition of Customer Care's social media efforts to Public Affairs (Corporate Communications) occurred seamlessly and as planned.

The internal CS meetings increased overall situational awareness and ability to respond to the customer-owner inquiries.

Two areas to improve customer engagement surfaced during this phase of the event. First, an earlier review of the load-shedding blocks may have better prepared CS to develop messaging and services targeted to the customers who were going to be impacted. Secondly, the Customer Care representatives did not have talking points prior to the commencement of load shedding. This limited their ability to respond to general customer questions/concerns.

Response & Execution

The CS team demonstrated commitment, flexibility, and patience throughout the emergency event. OPPD received more than 4,000 calls during the load-shedding event and Customer Care representatives quickly adapted to the changing situation and increased call volume.

During this phase of the event, CS's collaboration with Energy Delivery's system operations specialists was critical. The Substation team was postured to quickly respond to circuits that would not close remotely.

Throughout the event, the following areas were identified for future consideration:

- **Process** – insufficient ability to identify critical-load customers and curtailment programs that are designed only for summer loads.
- **Communication** – external mass communication with small and medium-sized businesses was insufficient and the established procedure between CS and Public Affairs (total of five departments) delayed the approval process.
- **Resources** - resource materials were not provided early enough leaving Customer Care representatives challenged to address customer questions and concerns. Translation was not available at first for outbound customer messages.
- **Technology** – upgrades (or additions) to the outage map, customer notification preference center and CRM tool would improve OPPD's ability to manage customers (as required) through a load-shedding event.

Public Affairs

Preparation & Planning

The Public Affairs team was engaged and aware as the weather forecast worsened. Energy Regulatory Affairs was in touch with multiple external groups, including SPP and FERC, to better understand the challenges and implications of the impending weather event.

Environmental Affairs coordinated with city and state governmental entities, in particular the Nebraska Department of Environment and Energy, to secure waivers and approval to run additional generation which might exceed permit limits under normal circumstances.

The Corporate Communications team coordinated with the Customer Care team regarding social media messaging to achieve two goals: first, to relieve resources to allow Customer Care to respond more quickly to customers, and second to maintain a common and consistent message through all external sources. Due to uncertainty around what could transpire during the Polar Vortex, the team prepared a set of general materials for multiple media sources.

Areas identified for improvement include: Improved coordination with Energy Delivery on the load-shed plan and better understanding how to communicate it would be beneficial. Plus the development of communication templates for impending weather events, particularly in the days leading up to a potential event when the goal is to advise but not raise fear, would be helpful to develop in advance.

Response & Execution

The Public Affairs team was highly engaged during the most intense two days of the polar vortex. With the initial unprecedented request from SPP to implement region wide load shedding for the first time in this region's history there were initial internal and external communication challenges, but by Monday afternoon the communications team was able to fully meet internal and external needs.

Energy Regulatory Affairs established regular communications with SPP and FERC to inform decision-making and influence how outages were coordinated in an effort to protect the bulk electric system. Existing relationships with utility peers, including Nebraska Public Power District (NPPD) and Lincoln Electric System (LES), were invaluable to ensure the industry was aligned regarding to public communication, and the overall messaging aligned with SPP.

Initially, it was challenging to develop communications with proper messaging at the beginning of the load shedding event. As an example, Employees noted the home page of the Intranet site did not focus messaging on the emergency event, but on more trivial, in comparison, information.

Additionally, enhanced technology would provide improved and efficient messaging, to create a more streamlined approach for different messaging across both media and customer recipients. The approach of the CEO providing individual interviews, rather than holding a press conference, led to layers of messaging which would not have happened with a press conference approach. Social media communications capabilities and staffing should be re-evaluated for these types of events.

Business Technology & Building Services (BTBS) / Safety & Technical Training (S&TT) / Human Capital (HC) / Corporate Strategy & Governance (CS&G) / Executive

Preparation & Planning

This section captures the planning and preparation efforts from an enterprise perspective. OPPD continuously prepares for extreme weather events. A significant aspect of preparation is OPPD's strong commitment and investment in preventative maintenance; to ensure critical assets perform under stress. Preventative maintenance coupled with the organization's ability to quickly and effectively prepare for and execute the load-shedding plan is noteworthy. Additionally, the agile communication with the Board of Directors and the Board's support positively impacted OPPD's ability to prepare for and respond to the Polar Vortex event.

The BTBS team played a critical role in this phase. Corporate Security proactively coordinated with NPPD and LES to share information and resources with the intent of protecting OPPD's critical infrastructure. This effort also extended to the partnering with law enforcement organizations and the monitoring of social media for signals or warnings.

Per executive feedback, there were two areas warranting further review and consideration include: providing one initial press conference versus multiple media outlet engagements to efficiently and effectively communicate a clear and consistent message. And, SMT's management of the event was largely ad-hoc in nature, and while prudent decisions were made based on the successful execution of the controlled outage process and maintaining our fleet generating power, a more structured approach would have been beneficial.

Response & Execution

This section captures the response and execution efforts from an enterprise perspective. OPPD is exceptional in responding to an emergency or extreme weather event. The passion of OPPD employees to serve and the agile communication and collaboration amongst the SMT are noteworthy and to be recognized. The District's training, preparation, caring, and leadership resulted in zero injuries, DARTs, or SIFs the week of and after load shedding.

A few areas were identified for future consideration and refinement:

Ensure appropriate personnel are informed and trained to execute the plan. For example, an increased legal review of load shedding, black start and any other NERC-required plans could have been requested and conducted either ahead of the event, or as the event unfolded. Overall, there were varying levels of knowledge/understanding of the load-shedding plan and potential impacts to OPPD facilities (e.g. EP, ECC).

OPPD's primary command, control and communications plan performed well. However, there was limited awareness of and ability to execute the secondary and tertiary back-up plans.

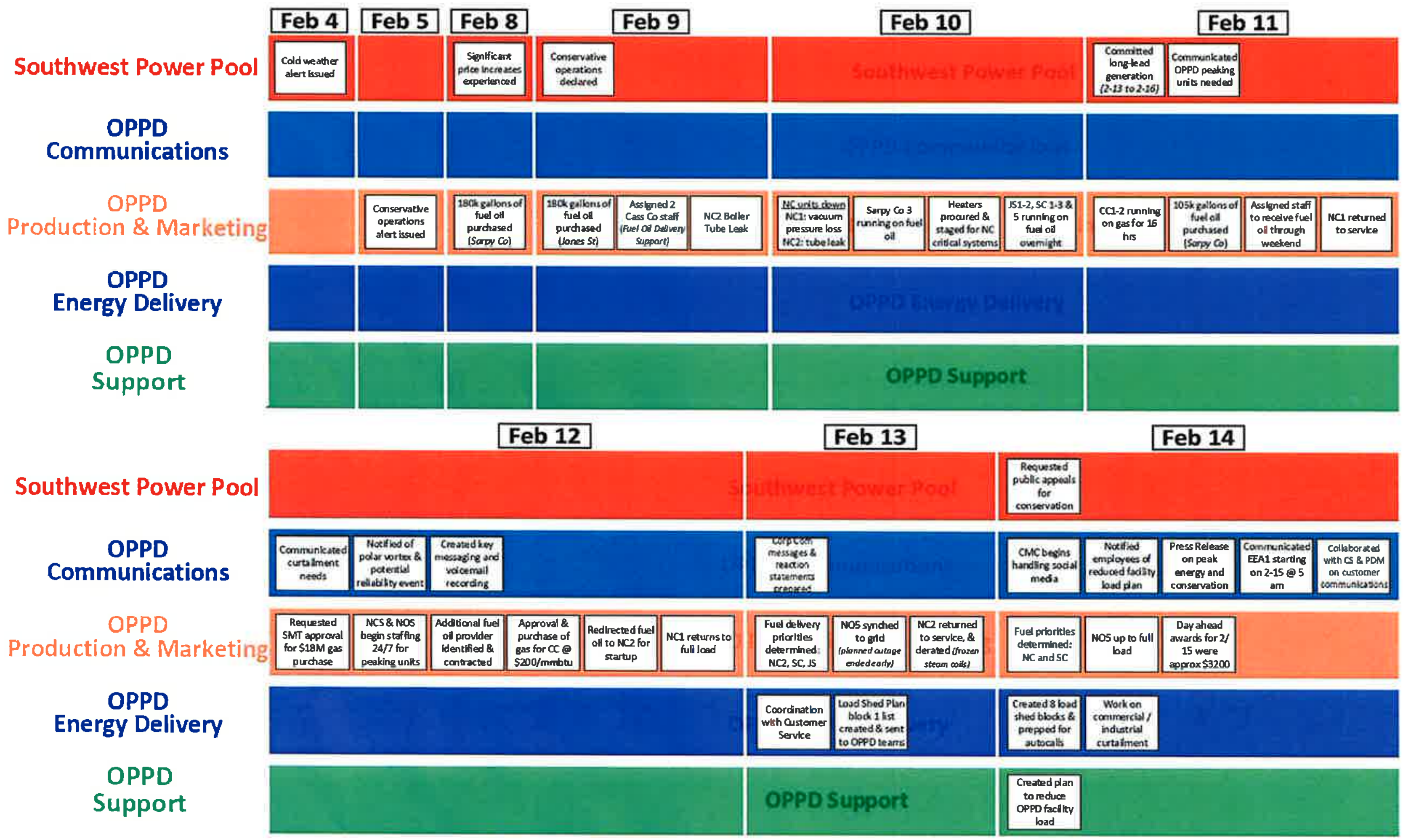
Also the ability to increase awareness of the potential of increased cyber-attacks could have been identified sooner.

Beyond the load-shedding plan, it was noted OPPD does have a robust framework for storm events and business continuity events but no specific (District-level) plan for non-storm grid emergency events.

Lastly, OPPD should focus on employee fatigue and mental well-being throughout the enterprise during and after any stressful event. Specifically focus on the operational areas most heavily called upon during a resiliency event including the Call Center, the Energy Control Center, Energy Marketing & Trading, and the Generation sites.

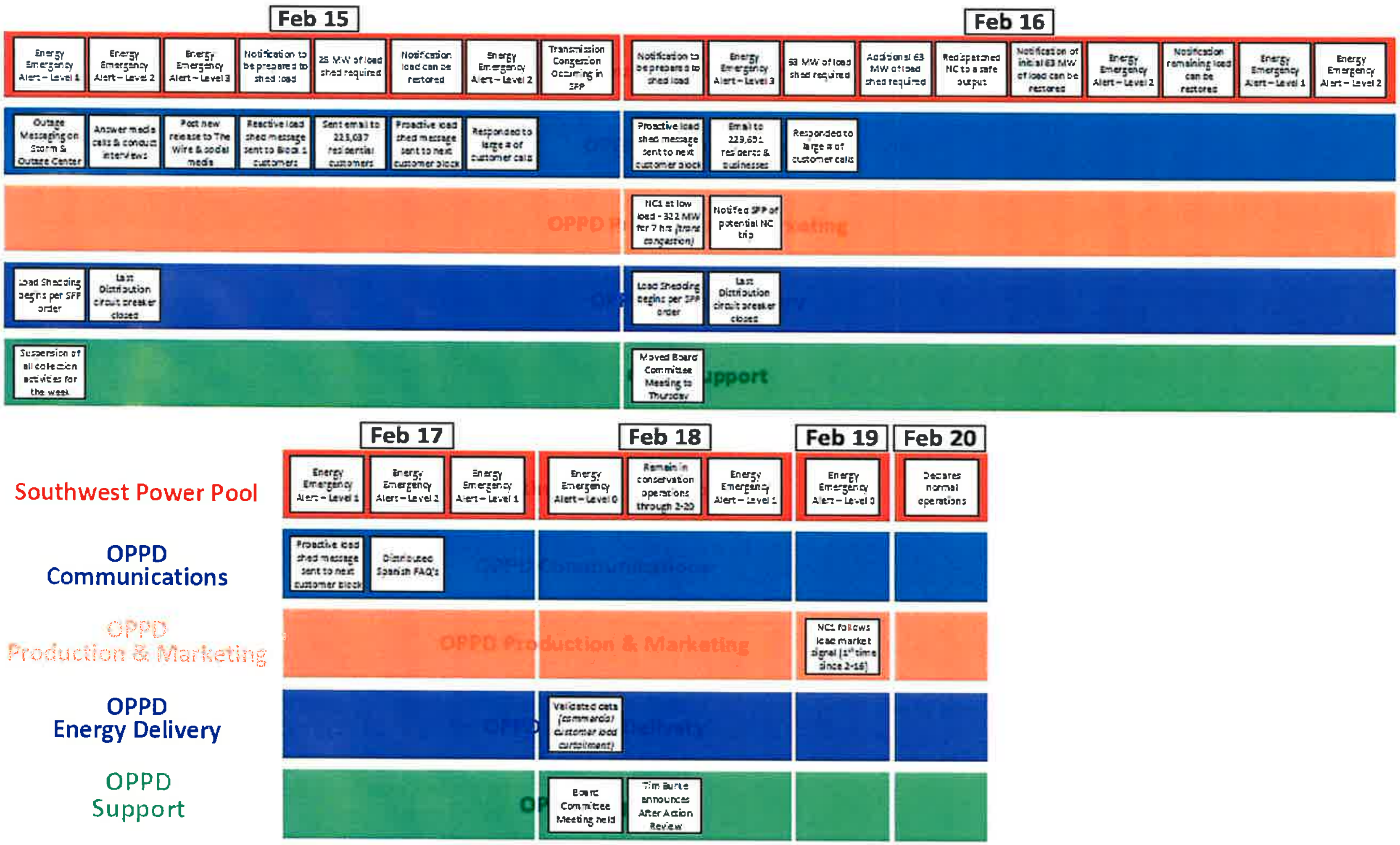
Visual Timeline (Pages 21 and 22)

The next two pages provide a high level summary view of the significant actions that took place during each day of the event. The goal of this view is to quickly show what actions, many happening simultaneously, were occurring as OPPD prepared and responded to this event. This event was a first of its kind for both OPPD and SPP and a visual layout of each day's actions better convey its complex nature and the heroic efforts of OPPD employees to maintain the integrity of the bulk electric system.



Acronyms

NC: Nebraska City Station, NC1 – Unit 1, NC2 Unit 2
NO: North Omaha Station, NO5 – Unit 5
SC: Sarpy County Peaking Station, Units 1-5
CC: Cass County Peaking Station, Units 1-2
JS: Jones Street Peaking Station, Units 1-2
CMC: Corporate Marketing & Communications
EEA: Energy Emergency Alert Levels 1-3
CS: Customer Service
PDM: Product Development & Marketing
SMT: Senior Management Team
MW: Megawatt
SPP: Southwest Power Pool



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CS: Customer Service
PDM: Product Development & Marketing
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SPP: Southwest Power Pool

Polar Vortex Explained

What is the Polar Vortex?

The polar vortex is a circulation of strong, upper-level winds that surround the artic. These winds tend to hold the bitterly cold polar air in the Artic regions of the Northern Hemisphere. Occasionally, the vortex is disturbed, begins to wobble, and these distortions reach much farther south than is normal. Given the wobbly nature of such an event, only portions of the Northern Hemisphere will experience the extremely cold temperatures that come with a polar vortex event. Each event is different, not only by the area it impacts, but the severity of the event itself can also vary greatly. All polar vortex events bring cold weather, however the most impactful events bring extremely cold temperatures for an extended period of time. When this occurs, especially when an event is particularly strong in both intensity and duration, it is a significant risk to the health and safety of the populations impacted.

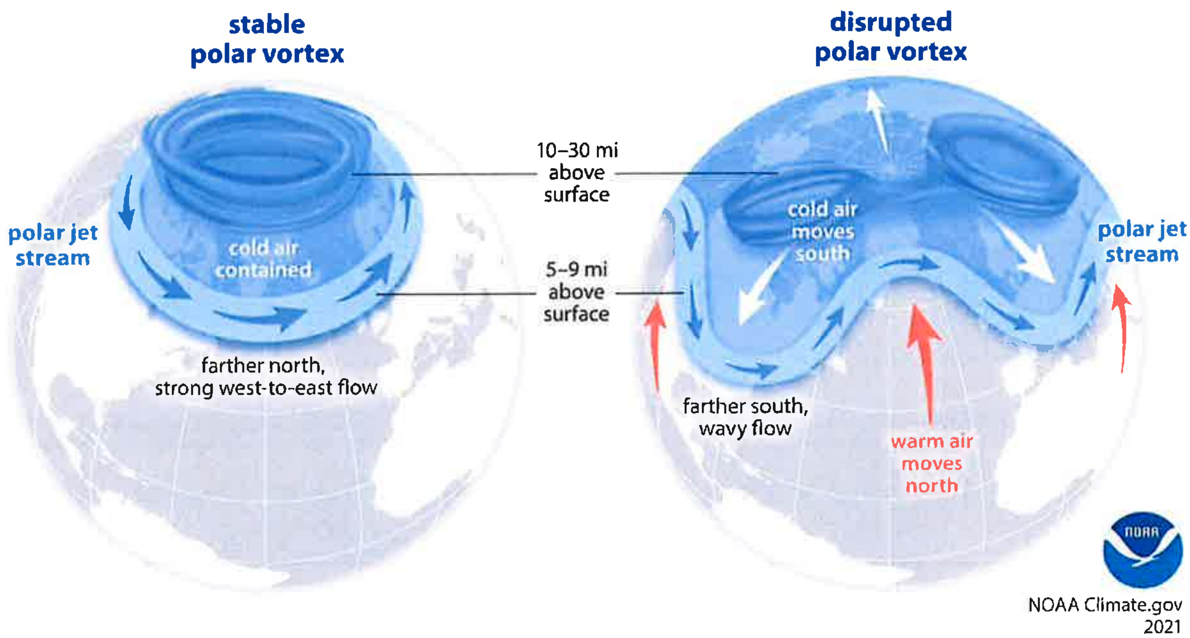


Figure 3 – NOAA: What is the Polar Vortex?

Some additional external links with more information on this topic are:

Jones, J., Miller, B., & Duke, A. (2019, January 30). *Polar vortex: Your questions answered.* CNN. https://www.cnn.com/2019/01/28/us/polar-vortex-explained-wxc/index.html.

US Department of Commerce, N. O. A. A. (2018, March 27). *What is the POLAR VORTEX?* National Weather Service. https://www.weather.gov/safety/cold-polar-vortex.

Understanding the arctic polar vortex: NOAA Climate.gov. Understanding the Arctic polar vortex | NOAA Climate.gov. (2021, March 5). https://www.climate.gov/news-features/understanding-climate/understanding-arctic-polar-vortex.

How significant was this event?

The February 2021 polar vortex event was significant compared to other polar vortex events or extreme cold snaps, at least as far as observational data allows for historical comparisons. The geographic area impacted and the duration of the extreme cold were both historic in their intensity. The earlier section on the weather event covered how severe this polar vortex event was compared to normal. To understand this event at a more local level, additional research was conducted by the National Weather Service office in Valley, Neb.

For the Omaha area in particular, the region sees three or more consecutive days of below zero average temperatures roughly every 5 years, when reviewing temperature data from 1900 to current. This past February the region saw a 3-day event (Feb 7-9) followed by a 5-day event (Feb. 12-16). Prior to the 2021 event, the region hadn't see an event meeting this definition since 2004, which was the longest period of time between events in different years in the entire period analyzed. The most significant events in the period analyzed was the winter of 1936, which was an 11-day, consecutive below-zero average temperature event, and the winter of 1983, which was a 9-day event.

It is important to note that any period of extreme cold in Omaha doesn't always indicate a polar vortex event. Extreme cold in Omaha does not always correlate with extreme cold across the SPP footprint. However, when extreme cold is seen in larger cities to our south (ex. Kansas City, Oklahoma City, and Dallas) there is generally extreme cold in Omaha at the same time. However, there are outliers to this data. For example, Texas experienced its last extreme cold load-shedding event from Feb. 1-5, 2011. Temperatures in Omaha at this time were not significantly cold, with the coldest day being 3 degrees above zero on average and the remaining days were above 10 degrees.

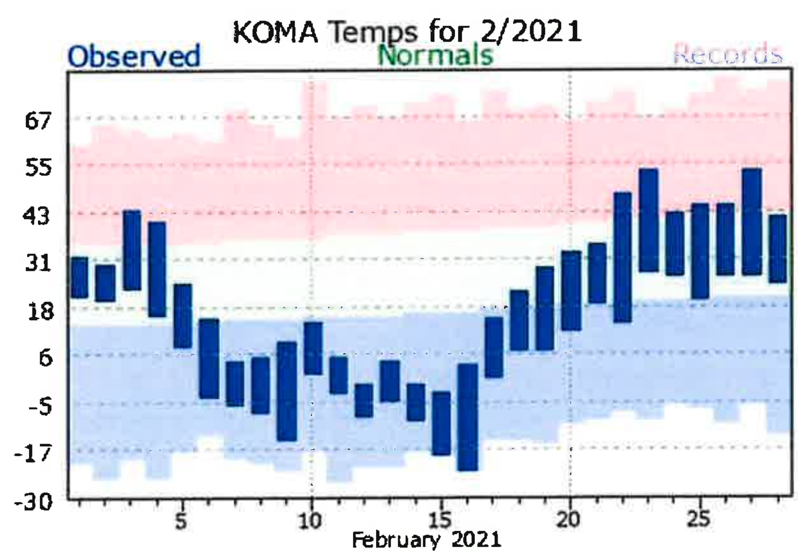


Figure 4 – National Weather Service (NWS) – Valley: Omaha Observed Temperatures Feb. 2021

Previous polar vortex events:

Wikimedia Foundation. (2021, March 24). *January–February 2019 North American Cold wave*. Wikipedia. https://en.wikipedia.org/wiki/January_February_2019_North_American_cold_wave.

Wikimedia Foundation. (2021, July 26). *December 2017–January 2018 North American Cold wave*. Wikipedia. https://en.wikipedia.org/wiki/December_2017_January_2018_North_American_cold_wave.

Wikimedia Foundation. (2021, February 22). *February 2015 North American Cold wave*. Wikipedia. https://en.wikipedia.org/wiki/February_2015_North_American_cold_wave.

Wikimedia Foundation. (2021, April 17). *November 2014 North American Cold wave*. Wikipedia. https://en.wikipedia.org/wiki/November_2014_North_American_cold_wave.

Wikimedia Foundation. (2021, June 30). *Early 2014 North American Cold wave*. Wikipedia. https://en.wikipedia.org/wiki/Early_2014_North_American_cold_wave.

Other external link to understand the significance of this event.

US Department of Commerce, N. O. A. A. (2018, February 8). *Monthly climate and records*. National Weather Service. https://www.weather.gov/oax/monthly_climate_records.

NOAA National Centers for Environmental Information, *State of the Climate: Synoptic Discussion for February 2021*, published online March 2021, retrieved on July 29, 2021 from https://www.ncdc.noaa.gov/sotc/synoptic/202102.

Assessing the U.S. climate in February 2021. National Centers for Environmental Information (NCEI). (2021, March 11). https://www.ncei.noaa.gov/news/national-climate-202102.

How often do polar vortex events occur?

The polar vortex, which is always present in the Artic during the winter, has been disturbed on average every other year since 2000, and even back to the 1970's when satellite data became widely available. That being said, each polar vortex event is different and will impact different portions of the Northern Hemisphere differently. The 1990's was an unusually quiet decade for polar vortex disturbances. This may be the result of some natural variability in the atmosphere, or it may be impacted by other external factors that scientists are still trying to understand. Direct measurements of the stratosphere, where the polar vortex resides, go back to the 1950s, which makes it difficult to understand what, if any, longer-term natural variability might exist with the polar vortex.

On the sudden stratospheric warming and polar vortex of early 2021: NOAA Climate.gov. On the sudden stratospheric warming and polar vortex of early 2021 | NOAA Climate.gov. (2021, January 28). https://www.climate.gov/news-features/blogs/enso/sudden-stratospheric-warming-and-polar-vortex-early-2021.

Was this event foreseeable?

Yes and no. It is possible to monitor and forecast the strength of the polar vortex around the North Pole. Climate scientists already identify when the polar vortex weakens and is disturbed, and even sometimes splits. When this happens it generally leads to greater variability in mid-latitude temperatures in the coming weeks.

That being said, as shown in the article provided below, the ability to predict where the polar vortex might bring extreme cold, and the duration and expanse of that cold, is beyond current weather forecasting capabilities. Surface-level and lower atmosphere conditions have a large impact on where and when this surge of Artic air will occur. Meteorology is generally only able to accurately predict coming weather conditions 7-14 days into the future. This is why it took until early February for various weather services to begin signaling the coming cold, despite the breakdown of the polar vortex in early January.

Kaufman, M. (2021, January 7). *The polar vortex has been disrupted. What does that bode?* Mashable. https://mashable.com/article/polar-vortex-explained.

Polar Vortex & Climate Change

The Earth's climate is an immensely complex system impacted by a multitude of factors along various time scales. The majority of climate scientists agree that the climate is warming overall and the National Weather Service-Valley analysis shows that Omaha's average temperature has warmed in the years 1900 to current. In general, this warming trend should result in winters that are less cold on average in the future compared to historical averages. Despite an overall warming trend, it is still possible to experience extreme cold spells and record low temperatures in any given winter.

The exact connection between climate change and how it will impact the polar vortex is not fully understood at this time. Some models indicate warming will strengthen the polar vortex, while others show it will weaken it. Regardless, more research is needed to better understand this phenomenon and its impact on weather and climate in the future.

Understanding the arctic polar vortex: NOAA Climate.gov. Understanding the Arctic polar vortex | NOAA Climate.gov. (2021, March 5). https://www.climate.gov/news-features/understanding-climate/understanding-arctic-polar-vortex.

Conclusion

The polar vortex event of February 2021 was an unprecedented event for the electric industry, OPPD, and our customer-owners. While the event was historic in its size, magnitude, duration, and the response necessary to preserve the integrity of the bulk electric system, it also was an opportunity for OPPD to learn and improve.

This after action report is intended to be the record of how OPPD prepared for and responded to this regional energy emergency event as well as to capture the improvements and lessons learned to be better next time. While the organization hopes that load shedding will never again be needed to maintain the stability of the grid, it is prudent to prepare in the event that it is. There are many factors that are beyond any utility's control when facing the threats of extreme weather events. This report demonstrates OPPD's responsibility to improve on what it can control to safeguard our mission of providing affordable, reliable, and environmentally sensitive energy services to our customers even in the most challenging of circumstances. As the recommendations included in this report are prioritized and implemented, the organization will continue to improve and advance our commitment as the trusted energy partner for the communities it serves.

Appendix

List of Polar Vortex After Action Review Interviews by Business Unit

List of Related External Reports on the 2021 Polar Vortex Event

List of Polar Vortex After Action Review Interviews by BU		
Name	**Position**	**Business Unit**
Jake Farrell	Manager, Building Services & Operation	BTBS
Owen Yardley	Director, Building Services & Corp Security	BTBS
Dave Whisinnand	Director, Ent Infrastructure	BTBS
Kate Brown	VP & CIO, Business Technology & Building Services	BTBS
Meredith Comstock	Supervisor, Building Services & Operations	BTBS
Chris Fosmer	Supervisor, Building Services & Operations	BTBS
Nicole Luna	Customer Experience Designer	CS
Nitin Gambhir	Customer Care Coordinator	CS
Pat Almgren	Supervisor, Customer Care Services	CS
Hallie Rodis	Supervisor, Customer Care Services	CS
Shenisa Neal	Supervisor, Customer Care Services	CS
Beth Klauschie-Perez	Supervisor, Customer Care Services	CS
Tracy Herman	QA & Metrics Specialist	CS
Lindsay Grashorn	Business Solution Representative	CS
Omar Alnazer	Lead Representative	CS
Gabi McVay	Call Center Representative	CS
Andrew Ciurej	Call Center Representative	CS
Aaron Smith	Director, Customer Experience	CS
Steve Sauer	Manager, Large C&I Sales & Services	CS
Jim Krist	Director, Customer Sales & Services	CS
Ron Mahoney	Senior Account Executive	CS
Donna Miner	Manager, Customer Operations	CS
Heather Siebken	Director, Product Development & Marketing	CS
Corey DeJong	Manager, Product Marketing	CS
Wyndell Young	Manager, Mid/Small C&I Sales & Services	CS
Jay Schubert	Engineer III	CS
Juli Comstock	VP, Customer Service	CS
Moe Hinners	Senior Corporate Governance Specialist	CSG
Scott Focht	VP, Corporate Strategy & Governance	CSG
Neal Faltys	Principal Engineer	ED
Amanda Underwood	Senior Engineer	ED
Mike Herzog	Manager, Distribution Planning	ED
Todd Gosnell	Manager, Ops Engineering & Training	ED
Matt Shanzt	Lead Distribution Operations	ED
Joel Adams	Distribution System Operator	ED
Doug Peterchuck	Manager, Transmission Operations	ED
Rita Hatfield	System Operations Specialist	ED
Brad Heimes	Lead Transmission Operations	ED
Joel Adams	Distribution System Operator	ED
Troy Via	VP, Energy Delivery	ED

Name	Position	Business Unit
Eric Yowell	Transmission System Operator	ED
Lee O'Neal	Director, T&D Construction	ED
Brian Kramer	Manager, Substation & System Protection	ED
Adam Staebell	Manager, Maintenance Services	EPND
Kyle Brinkcerhoff	Manager, Maintenance Services	EPND
Clint Zavadil	Manager, System Engineering	EPND
Gary Ruhl	Manager, Programs	EPND
Claude Strope	Lead Engineer	EPND
Tim Uehling	Senior Director, FCS Decom	EPND
Todd Anderson	Lead Engineer	EPND
Scott Eidem	Director, Engineering Services	EPND
Barb Parolek	Fuels Supply Manager	EPND
Deb Burns	Fuels Supply Manager	EPND
Ryan Stigge	Program Manager, Decarbonization SI	EPND
Kelly Anderson	Supply Doc Control Admin Support	EPND
Joseph Mise	Engineer III	EPND
Bud Chapin	Director, Maintenance Services	EPND
Mary Fisher	VP, Energy Production & Nuclear Decommissioning	EPND
Ryan Gerdts	Manager, Station Operations	EPND
Allan Vacek	Manager, Station Operations	EPND
Justin Wiemer	Supervisor, Peaking Stations	EPND
Ryan Headley	Manager, Energy Marketing	FS
Justin Kathol	Manager, Settlements & Risk	FS
David Theobald	Senior Term Trader	FS
Rick Yanovich	Structured Deal & Congestion Trade Manager	FS
Mark Trumble	Director, Energy Marketing & Trading	FS
Joel Robles	Senior Energy Coord NERC Comp & Training	FS
Mike Donahue	Manager, Transportation & Construction Equip	FS
Tim McAreavey	Director, Supply Chain Management	FS
Jane Metzer	Supervisor, SCM Warehousing	FS
Javier Fernandez	VP & CFO, Financial Services	FS
Joe Waszak	Senior Settlement Analyst	FS
Chris Campos	Day Ahead Energy Marketer	FS
Ryan Murphy	Day Ahead Energy Marketer	FS
Brad Underwood	Director, Financial Plans & Analysis	FS
Mart Sedky	VP, Human Capital	HC
Steve Bruckner	General Counsel	LEGAL
Tim Burke	President & CEO	OPPD
Joe Lang	Director, Energy Regulatory Affairs	PA
Mahmood Safi	NERC Compliance Manager	PA
Kate Thomas	Director, Corporate Market & Communication	PA

Name	Position	Business Unit
Mary Oswald	Manager, EE Communication & Collaboration	PA
Jeremy Bowers	Director, Environmental & Regulatory Affairs	PA
Bryan Lorence	Manager, Environmental Operations	PA
Kerri Teter	Sr. Environmental Specialist	PA
Bob Holmes	Program Administrator	PA
Lisa Olson	VP, Public Affairs	PA
Kevin McCormick	Senior Director, Safety & Technical Training	S&TT

Count by Business Unit	TOTAL
BTBS	6
CS	21
CSG	2
ED	14
EPND	18
FS	14
HC	1
LEGAL	1
OPPD	1
PA	9
S&TT	1
All Business Units	**88**

Links to Related External Reports on the 2021 Polar Vortex Event:

Southwest Power Pool (SPP)

https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf

SPP Independent Market Monitoring Unit

https://www.spp.org/documents/64975/spp_mmu_winter_weather_report_2021.pdf

Midwest Independent System Operator (MISO)

https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf

APPENDIX NO. 10

Atomic Insights, Performance of the New England power grid

Performance of the New England power grid during extreme cold Dec 25-Jan 8

January 26, 2018 By Rod Adams — 22 Comments

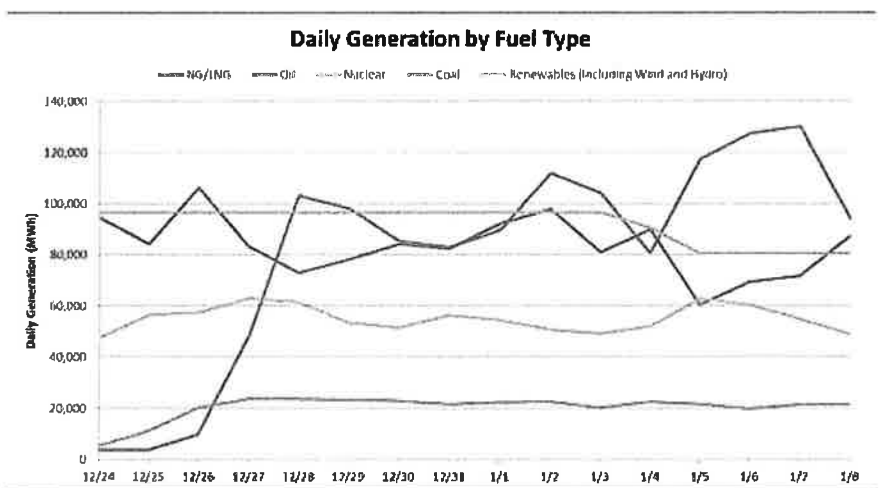
The Independent System Operator for the New England power grid (ISO-NE) has produced a summary brief describing the challenges associated with Arctic Outbreak 2017-2018, a period of substantially below normal temperatures that lasted from Dec.25, 2017 until Jan. 8, 2018.

After describing the intensity of the cold wave with a number of graphs, charts, images and words, the brief made the following sobering statements about the fuel mix used to supply power demand.

- Overall, there was significantly higher than normal use of oil
  – Coal use also increased over normal use
- Gas and Oil fuel price inversion led to oil being in economic merit and base loaded
- As gas became uneconomic, the entire season's oil supply rapidly depleted

The brief includes the following graph showing the daily electricity contribution in MWhrs from various fuel sources.

Daily Generation by Fuel Type (MWh)



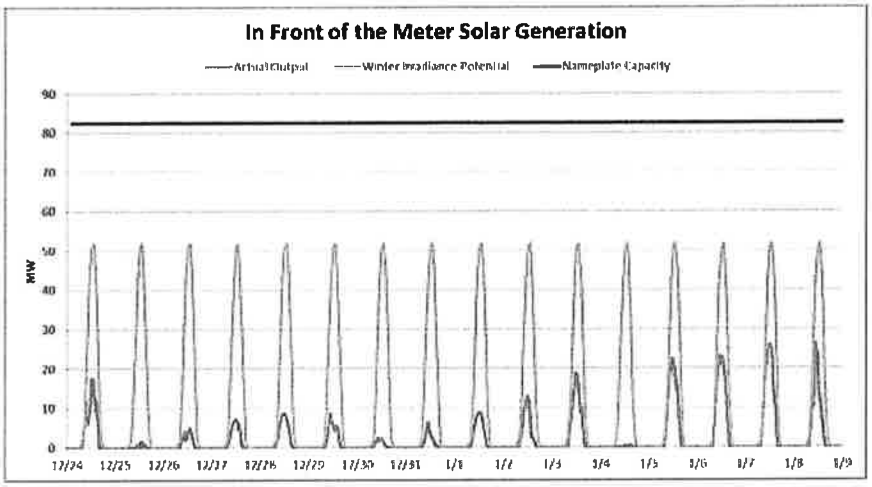
A major contributing factor to the rapid depletion of fuel inventories was the sharp increase in oil-fueled power production starting on Jan 4. Nuclear electricity production dropped on Jan 4 by about 8,000 MWhrs and dropped again on Jan 5 by roughly the same amount.

Pilgrim Nuclear Power Plant was scrammed at about 1:15 pm on Jan 4 because one of its two large transmission lines fell down during Winter Storm Grayson. The plant, which had been running continuously at or near full power for 225 days, was not returned to service until Jan 10 and did not achieve full power output until Jan 12.

The majority of the power that had been supplied by Pilgrim was replaced by burning more oil. As the winter storm moved away from the region, generation from wind also fell.

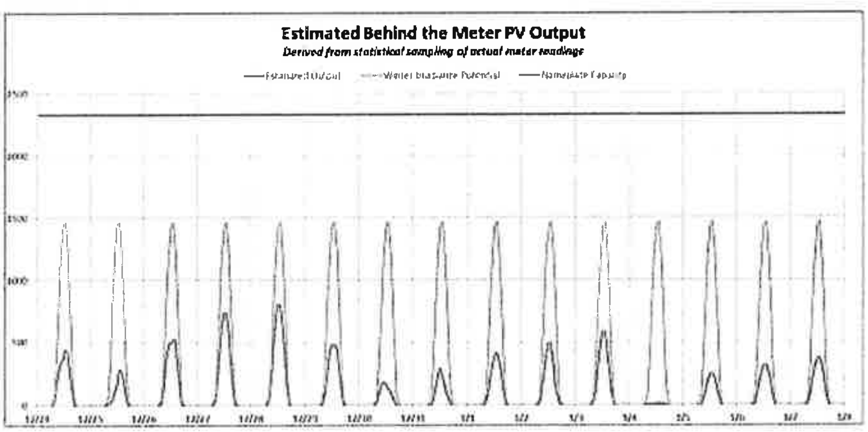
The below pair of charts from the brief should also be food for thought for those who claim that what regions like New England really need is more solar power.

PV Generation – In Front of the Meter



Note: PV resources in front of the meter are intended for supplying the grid.

PV Generation – Behind the Meter



Note: PV behind the meter are intended mainly for on-site generation.

Fuel supply challenges

Though there were no large scale power outages, keeping power flowing to customers required some heroic efforts on the part of fuel truck drivers, Coast Guard ice breakers, and power plant operators.

It even required the suspension of usual rush hour traffic procedures that prevent the Weymouth Fore River Bridge from opening. As the Coast Guard explained in its press release announcing the temporary allowance for critical vessel traffic, "...recent extreme weather and ice accumulation in the Weymouth Fore River has made it difficult for tank vessels and barges to deliver time-sensitive resources such as home heating oil and kerosene, and fuel for power plants and public transit."

Even though road conditions were treacherous, fuel trucks were pressed into overtime service to prevent the catastrophic consequences of running out of fuel during an event where temperatures were often well below 0 °F and the wind was howling. Keeping fuel oil supplied to homes, businesses and power generators required the suspension of normal driver rest requirements.

The ISO-NE brief describes trucking as the main fuel supply logistical constraint and states that:

- Carriers are at their physical limits
- Drivers need time off to rest, even with State Waivers in effect
- The break in the weather this week [beginning Jan 8] will provide much needed relief

Both the rush hour bridge openings and the suspension of truck driver rest rules had the potential to alert large segments of the population to the fact that their electricity supply system was closer to collapse than sunny summary statements of "reliable performance" might imply. Fortunately, no tragic consequences occurred – this time.

Not a perfect storm

Though the weather event was unusual, it was certainly not unprecedented. It's no surprise to note that it sometimes gets cold and dark in New England during the winter. There are some who incorrectly label the entire event as a "bomb cyclone," overlooking the fact that moniker only applies to the rather strong nor'easter that raced up the Eastern Seaboard on Jan 4.

Others with longer memories apply a more accurate label of "New England winter," to reflect the fact that winter weather can vary from year to year, but it is something that requires routine preparations. It isn't a surprising act of God when it is a little colder than average, just as it shouldn't be surprising when a winter ends up to be a bit warmer than average.

Senate Energy and Commerce Committee Hearing

On Tuesday, Jan 23, 2018, Senator Lisa Murkowski, the Chair of the Senate Energy and Natural Resources Committee, convened a hearing to discuss the performance of the electric power grid during certain weather conditions. Most of the testimony and questioning focused on the two week period from Dec 25-Jan 8, but the nature of the topic allowed participants to expand the discussion to other memorable weather events including droughts, heat waves and tropical cyclones.

Though it's possible for people to watch the archived video of the hearing and find reassuring commentary confirming whatever biases they have, I watched with growing concerns for New England's ability to handle routine weather events without major economic disruption and potential loss of life. (I'll admit that my training as a professional worrier – also known as an engineering officer in the Nuclear Navy – biases me toward concern when others are complacent.)

Mr. Gordon van Weile, the president and CEO of ISO-NE, provided both stark warnings for the future and a reminder that he has been sounding the warnings since at least 2013 without any substantive action being taken. Each time a non-gas fired generator retires, the situation gets more fragile. That is especially true when the retiring resource is a nuclear plant that has been reliably running at full power 80-95% of the time.

When there is a sustained cold weather event, natural gas availability hits a virtual wall where prices rise at astronomical rates indicating that there is no gas left to be purchased, no matter how much the buyer is willing and able to pay. When prices in a region rise to be 20 or more times higher on one side of a pipe compared to the other, it means there is no more room in the pipe.

Mr. van Weile described the precarious nature of New England's fuel supply during the cold spell.

> *While we weathered a stretch of extremely cold weather and a blizzard, we remain concerned about resupply of these resources during the remainder of the winter season and are in close coordination with state and federal officials about the challenges of ensuring adequate oil supplies to the region. Finally, given the fuel constraints, the rapid depletion of the oil inventory, and the reality that resupply was several days away during the peak of the cold weather period, our*

biggest operating concern was that we would experience a large, multi-day system contingency during this period or that oil-fired generators would run out of fuel before they could be resupplied.

Pilgrim's Jan 4-Jan 9 Shutdown

It's difficult, even during a period of incredibly steady performance by 98 out of 99 nuclear plants, to engage in discussions about the importance of nuclear energy for the resilience of the U.S. power grid when the 99th plant shuts down unexpectedly and remains shutdown for what is now going on six days.

paraphrasing a nuclear industry cliche, during a weather event an outage anywhere is an outage everywhere. That is especially true when it is unplanned and lasts an unexpectedly long time.

On the afternoon of January 4, the Pilgrim Nuclear Plant operators manually shut down their power station as a result of what I would term an overabundance of caution and fear of criticism from life-long opponents. The plant was returned to service almost six days later. Though the transmission line was back in service in approximately two days, the shutdown was extended because the plant operators decided to repair a small steam leak.

Aside: Steam plants leak. It is the nature of the technology. That is especially true as plants age. In many cases, the leaks are a minor annoyance and repairs can be deferred with no fixed deadline. It's dependent on situation; during one of my patrols we managed a rather irritating steam leak for more than a month so we could complete our scheduled mission. **End Aside.**

Investigation into details of Pilgrim's shutdown

The specific instigator of the decision to shut down was the loss of one of two 345 kV transmission lines that allow Pilgrim to deliver its power to the grid.

There is no external or regulatory requirement for a nuclear plant of Pilgrim's design to immediately shut down in such a circumstance. The required action is to work diligently on restoring the line and to limit the duration of operations with just one outgoing transmission line to a period of 72 hours. If the nature of the failure is such that it is unlikely to be resolved in the allowed time, most operators will choose to shutdown once that fact is known.

Pilgrim, however, has a local procedure that requires a prompt manual shutdown if it loses either one of its outgoing transmission lines during a storm event. According to Patrick O'Brien, that procedure was developed based on past operating experience. When one transmission line goes down, the plant is in a condition where the loss of the second line would result in an automatic trip and a more significant cycle on the plant's systems.

In response to a question about the possibility of delaying such a shutdown in a case where the grid operator had declared that the power was needed and shutdowns should be avoided, Mr. O'Brien stated that there is no process to allow situational judgement by plant operators. He acknowledged that there is a process by which a local procedure could be changed, but that requires a full impact review that cannot be waived.

During most of the period that Pilgrim was shutdown and completing the deferrable repair, the wholesale price of electricity in New England and New York averaged approximately $200 per MWh. As demonstrated during a separate period of demand caused by similarly cold weather with the plant operating, it is reasonable to state that lack of supply from Pilgrim added something close to $100/MWe to wholesale power prices.

If this analysis is correct, the loss of Pilgrim at a time of high demand cost New England customers approximately $1.5 million per hour. (Roughly 15,000 MW of demand x $100/MWh) On the other side of the ledger, a number of entities associated with fuel deliveries and power generators collected an extra $1.5 million per hour for six profitable days.

When operating, Pilgrim's daily electricity production is the energy equivalent of approximately 9,300 barrels of oil. Delivering that much oil to the generators that needed to run to replace Pilgrim required the logistic supply capacity equivalent of almost 50 large tanker trucks each day.

Pilgrim is scheduled to permanently close in early June 2019. Entergy, the plant's owner, has determined it is not profitable enough to overcome the costs, risks and managerial annoyances associated with operating the plant.

A loud and persistent subset of its neighbors has been vocally opposed to the plant's existence since before it was built.

Some of those neighbors vehemently and publicly protested Entergy's failure to shutdown the plant ***before*** the winter storm hit, claiming that the operators were putting profit over safety. When the plant did shutdown, those opponents did not petition for it to be restarted as soon as possible to keep the power grid secure, air pollution levels down, and electricity prices in check.

Instead, they staged a protest suggesting that the plant should be forced to remain shutdown and enter decommissioning a year ahead of the already premature date.

Here are excerpts from an email from Dianne Turco, the executive director of Cape Downwinders, explaining her organization's position regarding Pilgrim specifically and nuclear energy in general.

> *As an organization, Cape Downwinders is focused on public health and safety regarding the operation of Pilgrim. We support clean, green, renewable, and safe energy. Nuclear certainly does not fit in that category.*
>
> ...
>
> *It should be no surprise if Pilgrim goes down during a storm. That is one of the reasons why they are rated so low. In fact, in the past few storms, Entergy voluntarily shut Pilgrim preemptively. But not this time. They took the risk that threatens our entire region. Also, Pilgrim is not reliable baseload energy. When needed the most, Pilgrim has shutdown during blizzards and during the warmest days of the year due to temperature rise in Cape Cod Bay that interferes with the cooling water.*
>
> ...
>
> *Cape Downwinders position on energy is certainly no nuclear. Release of radioactive isotopes into the environment are part of the operation of a reactor. The National Academy of Science has determined there is no safe dose of ionizing radiation. Studies have shown cancer increases around nuclear reactors and after nuclear accidents. Dr. Richard Clapp, who was head of the MA Cancer Registry, found the closer one lived or worked in relation to Pilgrim, the incidence of cancer was 400% higher. We need clean, green, safe, and renewable energy for a healthy planet. Neither nuclear nor fossil fuels meet that criteria.*

I wasn't too surprised when she did not respond to my follow-up email.

> *Ms Turco*
>
> *Thank you for your response.*
>
> *This morning, when I checked the dashboards published by ISO-NE giving real time information on electricity and fuel sources, only 7% of the grid supply came from non hydro renewables. Nuclear and gas were each supplying 33%, oil and coal combined for 27%.*
>
> *93% of that 7% came from burning wood, refuse or landfill gas. 7% came from wind, 0% from solar.*
>
> *You have the luxury of advocating. Fortunately, there are other people working hard to supply reliable electricity from capable sources – nuclear, natural gas, oil and coal.*

The NAS says that evidence shows that radiation doses above 100 mSv can increase the risk of cancer. They also say that the risk increase is proportional to dose.

They say there is not enough evidence to conclusively show a threshold, so they make a conservative assumption and extend the proportional line down to zero risk at zero dose.

That means that risk is never zero, but approaches zero as doses approach the range of public exposure from nuclear power plants.

It is much, much lower than the health risk of exposure to below freezing temperatures.

Pilgrim is one of the worst licensed nuclear plants in the US, but it isn't unsafe any more than the worst player in the NFL is an unhealthy couch potato.

Rod Adams

With persistent opponents like Ms. Turco, it's understandable that a company might make the decision to exit. Operating power plants is hard enough when people occasionally express their appreciation for reliable service. It can be downright depressing to field sharp criticism for being unreliable after running for 226 days straight and maintaining a capacity factor in the neighborhood of 85% over a sustained period of years.

Why did Entergy take its time in returning Pilgrim to service?

Despite several attempts, I have been unable to determine the specific reasons why Entergy decided that they should take the opportunity presented by the downed power line to perform a repair that kept them from collecting revenues associated with generating power during a time of high demand and high prices.

It's not a simple task to determine just how much money Entergy left on the table by not operating. It isn't correct to simply take the wholesale price history and multiply it by Pilgrim's 685 MWe capacity because the prices would have been lower if Pilgrim had been operating.

However, it's clear that the steam leak repair cost several million per day in forgone revenues. Perhaps there were people in the decision chain that were reluctant to maximize their profits in the plant's final years of operation because they did not want anyone to suggest that the shutdown decision was based on economics that had been overcome by events.

Filed Under: Grid resilience

About Rod Adams

Rod Adams is an atomic energy expert with small nuclear plant operating and design experience, now serving as a Managing Partner at Nucleation Capital, an emerging climate-focused fund. Rod, a former submarine Engineer Officer and founder of Adams Atomic Engines, Inc., one of the earliest advanced nuclear ventures, has engaged in technical, strategic, political, historic and financial discussion and analysis of the nuclear industry, its technology and policies for several decades. He is the founder of Atomic Insights and host and producer of The Atomic Show Podcast.
Please click here to subscribe to the Atomic Show RSS feed.

Comments

Engineer-Poet says

January 26, 2018 at 11:47 AM

The depletion of New England's oil stocks from 68% to 19% (down 49%) in a matter of days is frightening. A little longer and the system would have run below minimum operating levels and TSHTF.

This problem will be greatly exacerbated by the scheduled closures of Pilgrim and Indian Point (especially the latter). If Pilgrim is equivalent to 9300 bbl/d, then Indian Point is equivalent to roughly 3x as much. Adding 37,000 bbl/d of oil demand during periods of gas network congestion would burn through reserves at lightning speed. Had those closures already occurred, the system would have had to go to rolling blackouts.

The necessity of the 90 day on-site fuel rule proposal is suddenly laid out in stark relief. It is time for the FERC to reconsider its rejection. It is also time to reconsider all pending nuclear closures and immediately change NRC rules to allow recommissioning of closed plants under their original license terms.

Last, am I the only one who noticed that there were wind-power curtailments due to transmission constraints despite the dire situation at ISO-NE? Those curtailments reached 200 MW at times. That's power that was literally left on the table and could probably have been scooped up for next to nothing. There's got to be some way to make productive use of it.

Reply

Wayne SW says

January 30, 2018 at 8:53 AM

Now imagine that the "reserve stocks" were composed of storage batteries (assuming such is possible for grid-scale applications, which has not been demonstrated) charged from solar panels and windmills, instead of oil in tanks somewhere. Depletion would occur overnight instead of over days. Bring on the rolling blackouts. I'd put Diane Turco and her friends at the head of the list for load shedding. Maybe put a mimic of the amp-hour battery reserves meter online for all to monitor. When it reaches zero, their computer shuts down.

Reply

Engineer-Poet says

January 30, 2018 at 11:35 AM

Computer? Shut down her heat, lights and water too. Make her endure the conditions she wants to inflict on everyone.

Given the capabilities of smart meters you could actually do this to her electricity. It would be funny to see how long she held out before saying uncle.

Reply

Rich says

January 26, 2018 at 12:35 PM

Wonder if the Envirowhackos have taken the data above and calculated how many Wind Turbines and Solar panels will be needed to provide the needed electricity? I have lived through at least four winter storms in the NE over a period of ten years that were very similar to that storm with similar energy problems.

I lived in Connecticut for five years and New Jersey for another five years after that. Both of my homes were heated by fuel oil, as it was much cheaper than NG. But I learned my very first winter that at the first report of an approaching winter storm to call the fuel oil company and have them top off the tank. There were two major reasons for this. If you wait till the tank is low and needs filled, if it happens to be in the middle of the storm you could pay near twice as much for the oil. Second reason is that once I was told that they had no oil for at least three days. However, I had a family with three young children.

While growing up on the farm we would use the fuel oi in our tractor when the tank was empty. So thinking they were the same I drove to the gas station and got several five gallon cans of diesel fuel. Although it burned, it did not have near the heat output of the fuel oil, but at least kept the house livable – with sweaters and extra blankets! My neighbors that had NG had to buy a Kerosene heater and kerosene the keep their home warm – which were selling for a premium during the storm, if you could find them.

Reply

FermiAged says

January 26, 2018 at 12:58 PM

How did the wind turbines perform during this period?

OT: Anyone have any info on the status of Sanmen?

Reply

Rod Adams says

January 26, 2018 at 1:42 PM

Good question.

Unsurprisingly, wind production included sharper and less predictable up and down ramps than solar.

https://twitter.com/atomicrod/status/956442121938063360

Reply

Pu239 says

January 29, 2018 at 8:11 AM

Bet you never thought you'd see the day they'd get 500-800 MW from wind for sustained periods. Have to admit if they triple the wind capacity, oil, gas, and coal could more easily fill the gaps.

Reply

Cory Stansbury says

February 10, 2018 at 8:23 AM

Sanmen has been done since late summer. It's been all politics since then as to when they'd fuel and start up. Very frustrating for those of us who worked on it. I think we're getting close though.

Reply

Rod Adams says

February 10, 2018 at 10:59 AM

@Cory Stansbury

Not terribly shocking to hear that there are politics associated with obtaining the final permissions to start up a nuclear power plant. Especially when it is an FOAK model of an imported, competitive technology to domestically available models.

I've never had a lot of trust in the Chinese government; I would not put it past them to exaggerate the challenges faced in building, starting and operating Westinghouse AP1000 reactors.

All the more reason for customers to select CAP1000 or Hualong One instead.

Reply

Jeff Walther says

January 26, 2018 at 1:48 PM

Nitpick: You've got the date of Senator Murkowski's hearing written as 2918. Pretty cool, if you can peer 1000 years into the future. A little surprising that Murkowski is still alive 1000 years hence, but encouraging. If she can hang on that long, perhaps I can as well... ☺

Thank you for continuing to bring the facts out into the light. Unfortunately, those paid to oppose nuclear will continue to be immune to facts. Is there any chance of getting a guest editorial or article in some of the regional papers? Get the residents' peril written somewhere they might read about it?

Reply

Ed Leaver says

January 26, 2018 at 10:34 PM

@Jeff:

You can lead a man to wonder, but you can't make him think. Facts don't change our minds. I've been in this area only since April. There's a mind-set. I don't know how universal, as I've only a sample of two. Both intelligent science-types. Both can do math.

But they don't. Over lunch one overcast day in an overcast week in overcast Bedford, discussing energy. Pointing out the deli window one asked, "So what is the solar Cf weeks like this?"

"Not much. Doesn't need to be. Plenty of sun in the desert southwest. 90% of the days are sunny. Just get it from there."

The other was an online discussion on a technical site, the question being from where the clean energy would come after Pilgrim went south? This was after having cited what had happened after Kewaunee closed, SONGS shuttered, and Vermont Yankee yanked:

"Local microgrids. Don't worry, it will all work out."

Pretty much by fiat: New England says no to natural gas, yes to renewables. (E&E News, October 2016.) Seriously.

Reply

Engineer-Poet says

January 27, 2018 at 6:55 AM

Should we accept that these people know what they want and deserve to get it, good and hard?

Or is this matter too important to let them serve as examples to the rest of us?

Reply

Rich says

January 27, 2018 at 9:26 AM

Problem I have with these "fairy dust" "Micro Grids" is that they increase the need, more than doubling the number of new transmission lines than presently existing transmission infrastructure. Reviewing the ISO-NE report they mentions several multiple events in neighboring areas, Next time you drive around look at where the transmission lines are.

Notice that there are often two or three sets of transmission lines running parallel for long distances, I recall in particular three 500Kv transmission lines running from Joliet to Chicago. A "Micro Grid" is going to require almost a spiderweb like system of transmission lines. This will mean many lower voltage transmission lines on essentially every major street and highway throughout your community. And that means many millions of dollars building those lines and more millions on "Mini Substations" to protect and switch the power to where it need to go.
The present lines and substations are also designed for delivering power in one direction and one direction only. Thus many more $millions will be expended to direct this power where it need to go and not dump highly destructive amounts of current onto a failure that "appears" to only be a sudden increase in needed power because of the loss of a PV network from a cloud passing over, when in reality it is a downed line.

Reply

Ed Leaver says

January 27, 2018 at 9:50 AM

@E-P
It's far too important. I doesn't serve as example to you, or me, or to essentially all other Rod's readers. Or James Conca (mostly).

I'm always impressed at the patience and equanimity with which Conca answers his critics. Rod and Meridith Angwin as well. Michael Shellenberger and Ben Heard. Why is Heard often considered the most dangerous enemy of the anti-nuclear movement? Watch his videos, listen to him talk. Or *The Atomic Show*. James Hansen is dispassionate as well, but its not the same. He may as well be invisible. Facts don't change our minds.

What does? I've backed off a bit while pondering that one. I've read and re-read Rod's letter to Ms. Turco, searching for question marks.

Didn't find one; suspect there's a reason. Could it have been better? The Monday-morning quarterback within suggests it might. Though NAS was well-covered, perhaps a brief sentence to the effect

> *(f) In general, increases in the incidence of health effects in populations cannot be attributed reliably to chronic exposure to radiation at levels that are typical of the global average background levels of radiation. This is because of the uncertainties associated with the assessment of risks at low doses, the current absence of radiation-specific biomarkers for health effects and the insufficient statistical power of epidemiological studies. Therefore,* ***the Scientific Committee does not recommend multiplying very low doses by large numbers of individuals to estimate numbers of radiation-induced health effects within a population exposed to incremental doses at levels equivalent to or lower than natural background levels****.*

Report of the United Nations
Scientific Committee on the Effects of Atomic Radiation,
Fifty-ninth session (21-25 May 2012) pg. 10.

In other words, there *is* a threshold.

But wait! *That's* not very brief! Coach reminds me attention spans are short, time had run out, and Rod was our man on the field.

I should shut up and tend my own backlog.

Reply

turnages says

January 27, 2018 at 7:20 PM

@Ed Leaver

A "brief sentence to the effect", eh? As you imply, the laboriously precise language of the UNSCEAR report isn't exactly that. Such language has its place, but not in speaking to ordinary people. I've tried to get it down a bit:

> *(f) In general, increases in the incidence of health effects in populations cannot be attributed reliably to chronic exposure to radiation at levels that are typical of the global average background levels of radiation.*
> *This is because of the uncertainties associated with the assessment of risks at low doses, the current absence of radiation-specific biomarkers for health effects and the insufficient statistical power of epidemiological studies.*

Translation: Radiation is all around us in nature. We have never been able to measure any bad health effects from it, even where the levels are high (up to 100mSv per annum). There are too many other real and worse causes of bad health.

> *Therefore, the Scientific Committee does not recommend multiplying very low doses by large numbers of individuals to estimate numbers of radiation-induced health effects within a population exposed to incremental doses at levels equivalent to or lower than natural background levels.*

Translation: And so it's nonsense to fabricate an alarming-sounding problem about radiation at these low levels, when there isn't one.

Does that sound about right? Short enough not to get a TL;DR response?

Reply

Wayne SW says

January 31, 2018 at 8:10 AM

So 90% of the days in the desert southwest are sunny. That's probably true. But there is this natural phenomenon called night, which happens at least once a day for about half the day. Last I checked, PV solar output was pretty limited during that time.

I had a pixie dust-type make the same argument with me, just get the solar PV from the desert. When I told him of the night effect, all I got was a blank stare. Another whacko type told me he had figured out that he could get all his electric car recharging from the PV panels he was going to put on his garage roof. I knew he worked during the day so I asked him if he planned to drive his electric to work. He did. But that was no big deal because he was going to recharge his EV overnight from the PV panels.

Doncha just love these people? They're so pathetic sometimes, its almost funny.

Reply

Jeff Walther says

February 1, 2018 at 11:43 AM

@Ed Leaver
""Local microgrids. Don't worry, it will all work out.""

You gotta love your faith based energy systems...

It's kind of like when I point out that logically, automation is going to reduce the needed work force to a shrinking fraction of the number of people who need jobs, and someone invariably points at the agricultural/industrial revolution and states that new jobs will appear. Faith based economics.

Sigh. These people were presumably trained to do analysis and should know that not checking the actual numbers is a recipe for disaster.

Reply

Martin Burkle says

January 27, 2018 at 5:29 PM

I too wonder what is happening at Sandmen. It was to go live in 2017.

Reply

Tony says

February 1, 2018 at 2:21 AM

Sanmen has not received permission to start the nuclear fuel loading process. No specific reason. Chinese Nuclear Regulatory Board demanded additional tests, which Sanmen passed, but still no decision from the Board.

China is traditionally very bureaucratic, and sadly delays like this is not uncommon in any sector.

Reply

Martin Burkle says

February 1, 2018 at 12:28 PM

Thanks
It is interesting to speculate about upcoming months. The 2nd AP1000 should be finished now and 6 months from now 2 more should be finished. I would start one up each 6 months.

Reply

Eino says

January 27, 2018 at 9:36 PM

It certainly sounds like there may be some cold days without furnaces in the new England area in the next few years. When the outage happens, this may be the time to send Dianne Turco a letter simply asking her if this ever happened when the nukes were operation. Then ask her which is more dangerous a minuscule amount of radiation or becoming a human popsicle.

Reply

Rob Brixey says

January 28, 2018 at 10:59 AM

The term "steam leak" lacks detail of severity.
As a BWR Operator, I know that plants are equipped with High Energy Line Break (HELB) Isolation functions that are designed to protect Safety Related Structures, Systems, and Components from the effects of a substantial "steam leak". Operators can evaluate the severity of a steam leak in a HELB instrumented system by parameters approaching an alarm or isolation set point. We monitor system flows and delta flows from one end of a system to another, ambient temperature and delta temperature (within a space or ambient to cooling water dT). The instrumentation is set to trigger isolations to prevent ambient conditions violating Environmental Qualifications (EQ). Some leaks just happen to be easier to find when at low power or shut down due to Heater Bay access restrictions at high power. There are leaks. And then there are LEAKS requiring a Secondary Containment EOP entry – which may eventually require a shut down. Insufficient detail in the press to judge if startup delay was warranted. Pilgrim is ran by sharp operators. I will implicitly trust their judgement.

Reply

Leave a Reply

You have to agree to the comment policy.

Comment

Name *

Email *

Replies to my comments

Notify me of followup comments via e-mail. You can also subscribe without commenting.

Post Comment

APPENDIX NO. 11

Black Hills Corp Provides Estimated Impact of Recent Cold Weather on its Utilities by State, News Release

March 1, 2021

Black Hills Corporation

NEWS RELEASE

Black Hills Corp. Provides Estimated Impact of Recent Cold Weather on its Utilities by State

3/1/2021

RAPID CITY, S.D., March 01, 2021 (GLOBE NEWSWIRE) -- Black Hills Corp. (NYSE: BKH) today released additional details regarding the impacts from the extreme cold weather during February on its utility businesses and customers. During this extreme weather event, the company's electric and natural gas systems performed remarkably and delivered energy safely and reliably to its customers.

In a Form 8-K filed recently, Black Hills indicated it incurred approximately $600 million of additional natural gas costs to meet customer demand through Feb. 24. The initial estimates of the incremental commodity costs to serveits natural gas and electric utilities' customers during the recent cold weather are generally as follows:

LR 49 EX 1

Arkansas Gas	$165 million
Colorado Gas	$75 million
Iowa/Nebraska	$190 million
Kansas Gas	$100 million
Wyoming Gas	$35 million
Total Gas Utilities	$565 million
Colorado Electric	$30 million
South Dakota Electric	$15 million
Wyoming Electric	$15 million
Total Electric Utilities	$60 million

These incremental commodity costs for February are initial estimates and subject to true-up as final accounting for tansactions and related activities are completed for February.

APPENDIX NO. 12

"THE BRATTLE REPORT"

Nebraska Renewable Energy Exports: Challenges and Opportunities

LB1115 Study

DEEMBER 12, 2014

Available in office of Natural Resources Committee

Nebraska Renewable Energy Exports: Challenges and Opportunities

(LB 1115 Study)

PREPARED FOR

NEBRASKA POWER REVIEW BOARD

PREPARED BY

Judy W. Chang

J. Michael Hagerty

Johannes P. Pfeifenberger

Ann Murray

December 12, 2014

THE Brattle GROUP

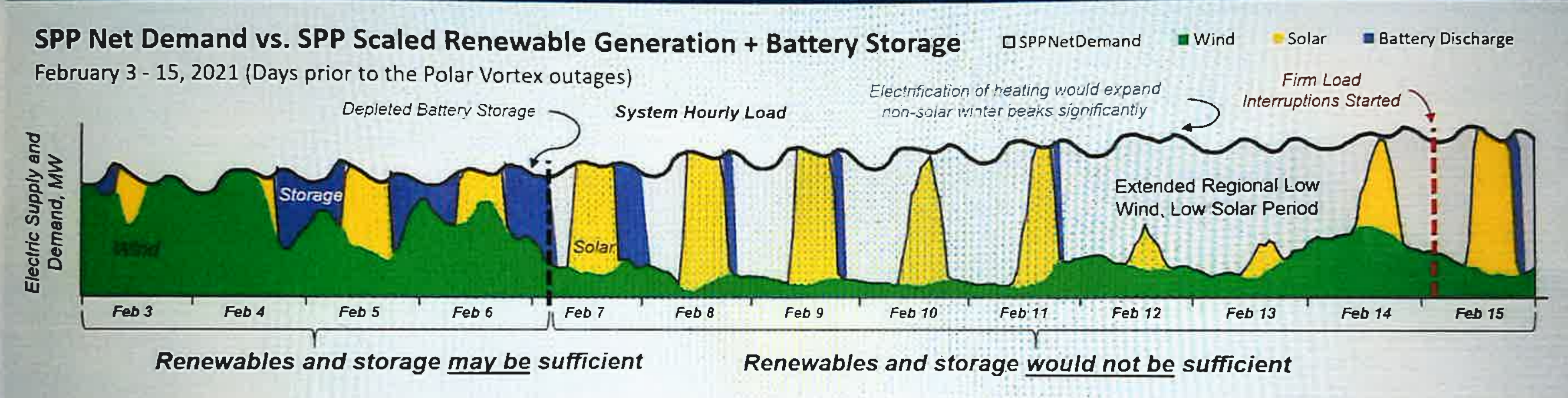
APPENDIX NO. 13

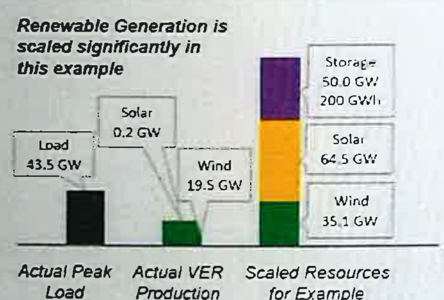
Environmental Economics, Reliability: Resource Adequacy, SPP March 2021

13

Reliability: Resource Adequacy

2021 SPP Polar Vortex Example





+ In February 2021 the SPP region experienced a Polar Vortex impacting generation and causing of insufficient generation to serve load. ALL types of resources were impacted by the event.
+ The graph illustrates how a portfolio of only renewables and energy storage would have performed in leading up to and in this event.
+ Renewable resources were producing, but at a lower levels than normal due to cloud cover and low wind speeds. These extended low renewable periods are known in the industry as 'Dunkelflaute' and challenge portfolios without firm dispatchable resources.

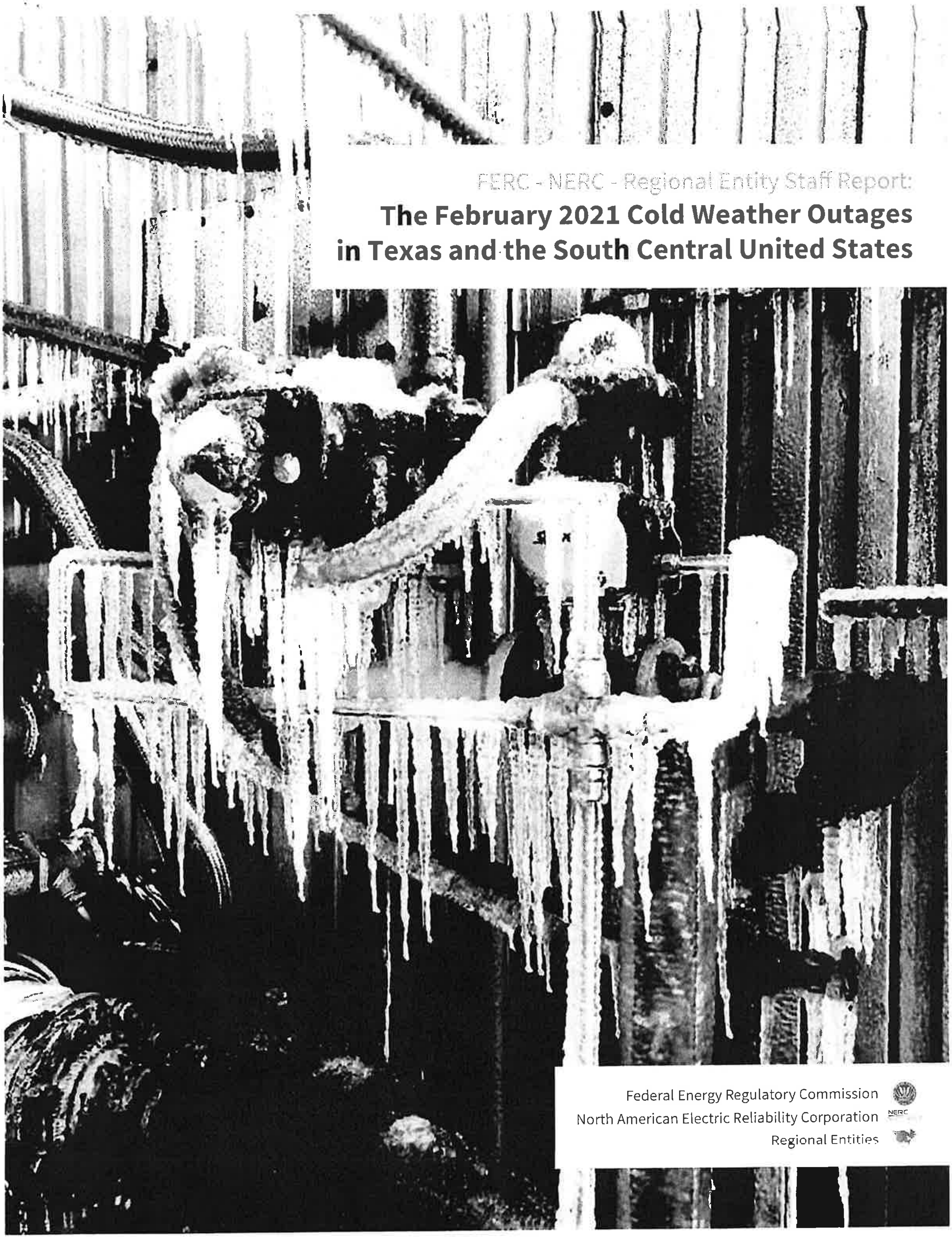
APPENDIX NO. 14

FERC, NERC Staff Review 2021 Winter Freeze, Recommend Standards Improvements

September 23, 2021

FERC - NERC - Regional Entity Staff Report:

The February 2021 Cold Weather Outages in Texas and the South Central United States



Federal Energy Regulatory Commission

North American Electric Reliability Corporation

Regional Entities

FERC, NERC and Regional Entity Staff Report

The February 2021 Cold Weather Outages in Texas and the South Central United States

November 2021

FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Entities:

Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Corporation, Texas Reliability Entity and Western Electricity Coordinating Council

Acknowledgement

This report results from the combined efforts of many dedicated individuals in multiple organizations. The inquiry team (the Team) consisted of individuals from the Federal Energy Regulatory Commission (FERC or the Commission), the North American Electric Reliability Corporation (NERC), Regional Reliability Entities Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), SERC Corporation (SERC), Texas Reliability Entity (Texas RE) and Western Electricity Coordinating Council (WECC), as well as the Department of Energy and the National Oceanic and Atmospheric Administration (NOAA), all of whom are named in Appendix A. They were assisted by other non-Team members within their respective organizations.

Contents

I. Executive Summary

This report[1] describes the severe cold weather event occurring between February 8 and 20, 2021 and how it impacted the reliability of the bulk electric system[2] ("BES" or colloquially known as the grid) in Texas and the South Central United States (hereafter known as "the Event"). During the Event, extreme cold temperatures and freezing precipitation led 1,045 individual BES generating units,[3] (with a combined 192,818 MW of nameplate capacity) in Texas and the South Central United States to experience 4,124 outages, derates or failures to start. Each individual generating unit could, and in many cases, did, have multiple outages from the same or different causes. To provide perspective on how significant the generating unit outages were, including generation already on planned or unplanned outages, the Electric Reliability Council of Texas (ERCOT) averaged 34,000 MW of generation unavailable (based on expected capacity[4]) for over two consecutive days, from 7:00 a.m. February 15 to 1:00 p.m. February 17, equivalent to nearly half of its all-time winter peak electric load of 69,871 MW.

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[1] This report is written for a reader who is already familiar with principles of energy markets, electric transmission system operations and generating unit operations. For readers who are not as familiar, the Team has linked to several resources which may be helpful:

[2] Bulk electric system generally means all transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. *See* NERC Glossary of Terms at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[3] A single generating unit can range from a 75 MW gas turbine, to a 1,000-MW-plus nuclear unit, to a wind farm with multiple wind turbines. For purposes of the report, only BES generating units were considered, i.e., those with a nameplate rating of 75 MW or higher.

[4] Expected capacity includes any expected seasonal capacity derates, and for intermittent resources (e.g., wind, solar resources), expected capacity is calculated based on weather conditions. For example, a 100 MW wind generation facility may be 20 MW, based on the variability of wind during the winter peak timeframe.

The Event was the fourth cold-weather-related event in the last ten years to jeopardize BES reliability,[5] and with a combined 23,418 MW of manual firm load shed,[6] the largest controlled firm load shed event in U.S. history. In each of the four BES events, planned and unplanned generating unit outages caused energy emergencies, and in 2011, 2014 and 2021 they triggered the need for firm load shed. The unplanned generation outages that escalated during the Event were more than twice as large as the previous largest event, in 2011 (65,622 MW versus 14,702 MW).

More than 4.5 million people in Texas lost power during the Event, and some went without power for as long as four days, while exposed to below-freezing temperatures for over six days.[7] At least 210 people died during the Event, with most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions.[8] Among the deaths were a mother and her seven-year-old daughter,[9] and an 11-year-old boy who died in his bed,[10] who all died of carbon monoxide poisoning, and a 60-year-old disabled man who died of hypothermia.[11] A grandmother and three children trying to keep warm

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[5] In February 2011, an arctic cold front impacted the southwest U.S. and resulted in 29,700 MW of generation outages, natural gas facility outages and emergency power grid conditions with need for firm customer load shed. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations (Aug. 2011) (https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf) (hereafter, 2011 Report). In January 2014, a polar vortex affected Texas, central and eastern U.S., triggering 19,500 MW of generation outages, natural gas availability issues and resulted in emergency conditions including voluntary load management. NERC "*Polar Vortex Review*" (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf (hereafter Polar Vortex Review). And in January 2018, an arctic high-pressure system and below average temperatures in the South Central U.S. resulted in 15,800 MW of generation outages and the need for voluntary load management emergency measures. See South Central United States Cold Weather Bulk Electric Systems Event of January 17, 2018 (July 2019), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf (hereafter, 2018 Report).

[6] Manual firm load shed, often referred to as rolling or rotating blackouts, is when BES operators order a percentage of the demand or load to be temporarily disconnected, to avoid system instability or other system emergencies. Customers lost electric distribution service due both to manual firm load shed, as well as to weather-related unplanned outages (such as downed power lines). In addition to being the largest controlled firm load shed event in U.S. history, the Event was also the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 Western Interconnection blackout.

[7] Paul Takashi, *I lost my best friend: How Houston's winter storm went from wonderland to deadly disaster*, Houston Chronicle (May 25, 2021), https://www.houstonchronicle.com/news/investigations/article/failures-of-power-series-part-2-blackouts-houston-16189658.php.

[8] Andrew Weber, *Texas Winter Storm Toll Goes Up to 210, Including 43 Deaths in Harris County*, Houston Public Media (July 14, 2021), https://www.houstonpublicmedia.org/articles/news/energy-environment/2021/07/14/403191/texas-winter-storm-death-toll-goes-up-to-210-including-43-deaths-in-harris-county/.

[9] ABC 13 Staff, *Carbon Monoxide "We tried our best to save them"*, ABC 13 Eyewitness News (February 17, 2021), https://abc13.com/houston-woman-and-daughter-die-from-carbon-monoxide-poisoning-mom-after-leaving-car-running-inside-garage-dangers-during-texas-winter-storn-storm-2021/10348847/

[10] KHOU Staff, *Autopsy Results Released for 11-Year-Old Who Died During the Texas Winter Freeze,* KHOU 11 News Channel (May 12, 2021) https://www.khou.com/article/news/local/conroe-police-autopsy-reveals-11-year-old-boy-died-carbon-monoxide-poisoning-houston-winter-storm/285-fbac9d3f-45cd-41bb-9047-33665fef8f18#:~:text=Autopsy%20results%20released%20for%2011,their%20mobile%20home%20lost%20power.

[11] Paul Takashi, *I lost my best friend: How Houston's winter storm went from wonderland to deadly disaster*, Houston Chronicle (May 25, 2021), https://www.houstonchronicle.com/news/investigations/article/failures-of-power-series-part-2-blackouts-houston-16189658.php.

using a wood-burning fireplace died in a house fire.[12] In cities including Austin, Houston and San Antonio, over 14 million people were ordered to boil drinking and cooking water, and multiple cities ordered water conservation measures, due to broken pipes and power outages (which lowered water pressure).[13] After the city of Denton, Texas, lost its gas supply, it was forced to cut power to nursing homes and water pumping stations.[14]

Analysts with the Federal Reserve Bank of Dallas estimated that the outages caused direct and indirect losses to the Texas economy of between $80 to $130 billion.[15] A separate Federal Reserve Bank of Dallas analysis described the effect on the petrochemical and refining sector as "hurricane-level," comparable to 2008's Hurricane Ike, with a 50 percent drop in February 2021 production as compared to January. It also predicted continuing effects on the supply chain through the end of 2021 as a result of the disruptions in February.[16]

A. Synopsis of Event

In the early morning hours of February 15, 2021, an arctic front moving through Texas and the South Central U.S. began to take its toll. As temperatures dropped, more and more generating units throughout Texas failed in ERCOT. The same front led to generating units to fail to a lesser extent in the South Central U.S. footprints of Midcontinent Independent System Operator (MISO) South and Southwest Power Pool (SPP).[17] Responding to the loss of generation, and to keep the electrical system from cascading outages and total blackout, the system operators at ERCOT began to issue orders for rotating outages of electricity to customers (known as manual firm load shed). ERCOT ultimately had to shed 20,000 MW of firm load at the worst point of the Event, with SPP and MISO

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[12] Anna Bauman, *Grandmother, 3 Children Dead in Sugar Land Fire*, Houston Chronicle (Feb. 16, 2021), https://www.houstonchronicle.com/news/houston-texas/houston/article/Sugar-Land-fire-fatalities-15953492.php%20https://www.google.com/amp/s/abc13.com/amp/sugar-land-house-fire-children-killed-deadly/10352669

[13] Talal Ansari, *New Winter Storm Threatens Fragile Power Grids in Texas, Other Parts of U.S.*, The Wall Street Journal New (Feb. 22, 2021), https://www.wsj.com/articles/new-winter-storm-threatens-fragile-electrical-grids-in-texas-other-parts-of-u-s-11613588298; Elizabeth Findell, *Texas Cities Under Boil-Water Orders*, The Wall Street Journal (Feb. 19, 2021), https://www.wsj.com/articles/texas-cities-under-boil-water-orders-11613671450.

[14] Community Emergency Preparedness Committee, *City of San Antonio Community Emergency Preparedness Committee Report: A Response to the February 2021 Winter Storm* (Jun. 24, 2021), https://www.sanantonio.gov/Portals/5/files/CEP%20Report%20Final.pdf; Russell Gold, *Inside One Texas City's Struggle to Keep Power and Water Going*, The Wall Street Journal (Feb. 17, 2021), https://www.wsj.com/articles/texas-city-deals-with-no-power-no-water-during-big-chill-11613590412.

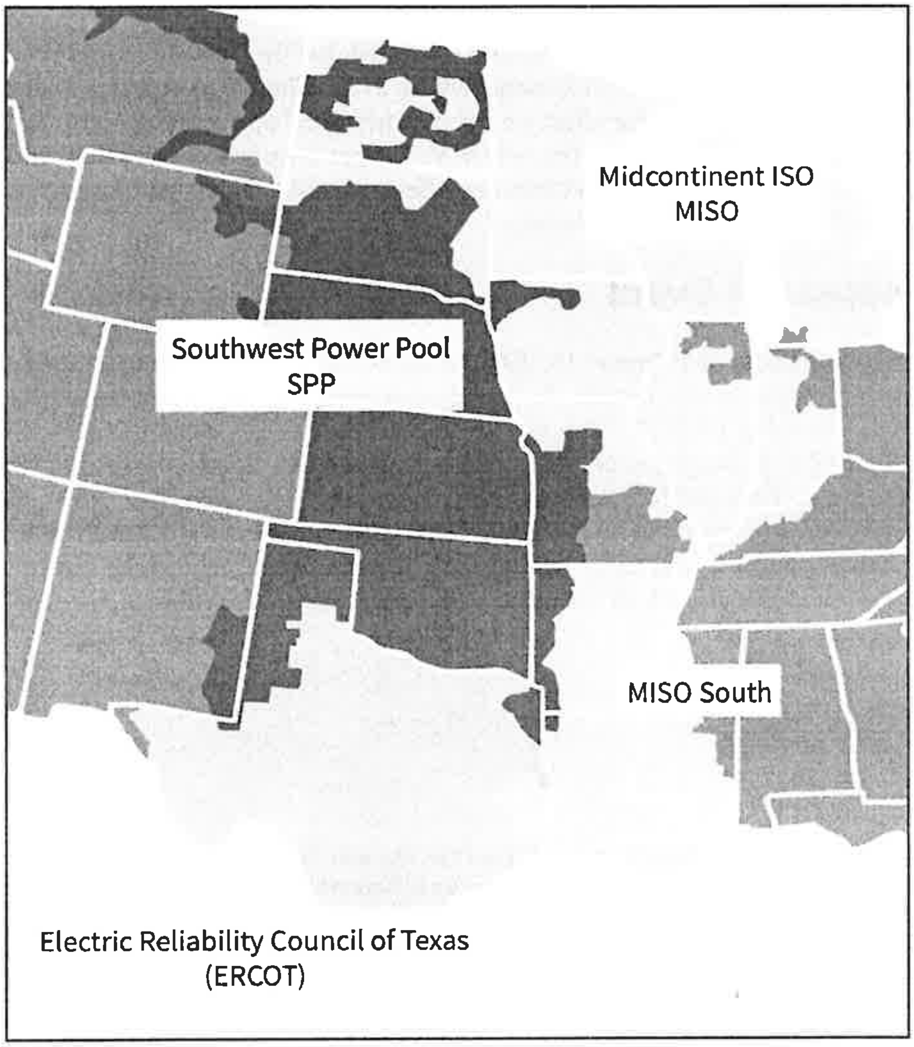
[15] Garrett Golding et al., *Cost of Texas' 2021 Deep Freeze Justifies Weatherization*, Dallas Fed Economics (Apr. 15, 2021), https://www.dallasfed.org/research/economics/2021/0415.

[16] Jesse Thompson, *Texas Winter Deep Freeze Broke Refining, Petrochemical Supply Chains*, Southwest Economy (Second Quarter 2021), https://www.dallasfed.org/research/swe/2021/swe2102/swe2102c (Texas holds nearly 75 percent of "basic U.S. chemical capacity," relied upon by global supply chains, and as much as 80 percent of this capacity was offline after the storm).

[17] See Figure 1 below for map of the Event Area: ERCOT, SPP and MISO South. Except for the figures regarding the entire MISO footprint in section II.B. below, the Team gathered data about and focused on MISO South, because the bulk of the manual load shed and unplanned generation outages experienced in MISO occurred in MISO South.

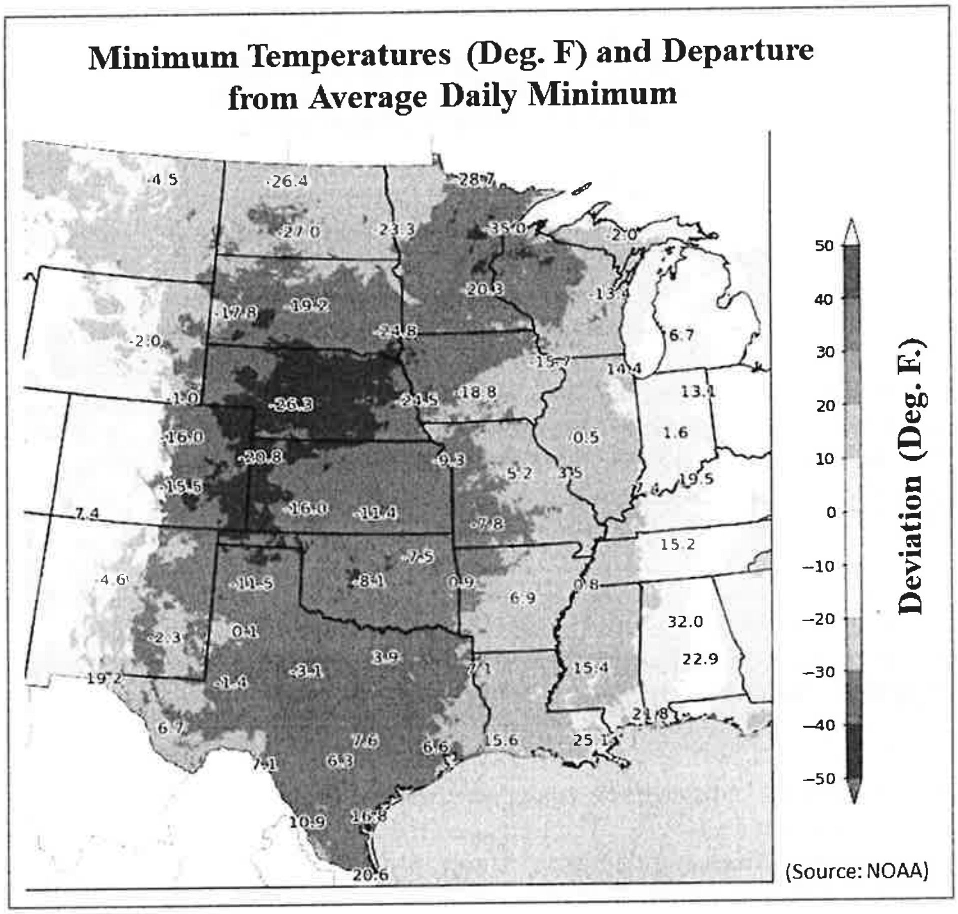
operators shedding a combined total of 3,418 MW of firm load on February 15 and 16, at their worst points.

Figure 1: Event Area: ERCOT, SPP and MISO South



A confluence of two causes, both triggered by cold weather, led to the Event, part of a recurring pattern for the last ten years. First, generating units unprepared for cold weather failed in large numbers. Second, in the wake of massive natural gas production declines, and to a lesser extent, declines in natural gas processing, the natural gas fuel supply struggled to meet both residential heating load and generating unit demand for natural gas, exacerbated by the increasing reliance by generating units on natural gas.[18] Natural gas pipeline capacity is for the most part designed, certificated and constructed to accommodate firm transportation commitments, while many natural gas-fired generating units rely on non-firm commodity and/or pipeline transportation contracts.

Figure 2: Severe Cold Weather Conditions – February 15, 2021



ERCOT, MISO and SPP all knew from weather forecasts and warnings issued by NOAA and other meteorologists beginning in early February that an arctic cold front was expected. All three issued cold weather preparation notices to their generation and transmission operators based on when the cold weather was expected to reach their respective footprints: ERCOT and SPP on February 8, and MISO on February 9. Temperatures began to drop below freezing in ERCOT and SPP on February 8, but low temperatures dropped even lower during the week of February 14, reaching their nadir on February 15 and 16. Daily low temperatures for February 15 in the Event Area were as much as 40

[18] Hereafter, "natural gas fuel supply issues" means the reduction in natural gas fuel supply caused by a combination of natural gas production declines, related natural gas pipeline pressure issues, and terms and conditions of electric generating units' natural gas commodity and transportation contracts.

to 50 degrees[19] lower than average daily minimum temperatures for February 15, as shown in Figure 2, above. In addition to the arctic air, the cold front brought periods of freezing precipitation and snow to large parts of Texas and the South Central U.S., starting February 10, and extending into the week of February 14, 2021.

Unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins[20] to prevent imminent freezing issues, beginning on approximately February 7, as well as unplanned outages of natural gas gathering and processing facilities, resulted in a decline of natural gas available for supply and transportation to many natural gas-fired generating units in the South Central U.S. Once natural gas supply outages began at the wellhead, they rippled throughout the natural gas and electric infrastructure, causing processing outages and reductions, pipeline declarations of Operational Flow Order (OFO)s[21] and force majeure, and outages and derates of natural gas-fired generating units. U.S. natural gas production in February 2021 experienced the largest monthly decline on record.[22] Between February 8 and 17, the total natural gas production in the U.S. Lower 48 fell by 28 percent. In the Event Area, Texas, Oklahoma, and Louisiana gas production at its lowest point of February 17 declined by an estimated 21 Bcf/d, exceeding a 50 percent decline when compared to average production in January 2021. Average production declines in those three states constituted over 80 percent of the total production declines across the lower 48 states during the period from February 15-20 when compared to average production in January 2021. Most producing regions of the U.S. saw a sharp decline and recovery associated with temperature—when temperatures fell, regional production dropped, and as temperatures rose after the Event, regional production recovered, ultimately to pre-Event levels by late February.[23]

During the week of February 7, ERCOT and SPP experienced rising load, as well as increasing generating unit outages, primarily caused by wind turbine blade freezing as a result of freezing precipitation, and natural gas fuel supply issues. Although ERCOT and SPP issued several alerts, they did not have to take any emergency actions because enough generation remained online to meet load.

But the week of February 14 brought far colder weather, and ERCOT, SPP and MISO all faced emergency conditions simultaneously. Temperatures dropped as low as six degrees in Austin, eight degrees in Dallas and ten degrees in Houston. Unplanned generating unit outages and derates in ERCOT escalated sharply in the late-night hours of February 14 into the early morning hours of February 15, and ERCOT set an all-time winter peak record for system load of 69,871 MW at 8:00 p.m. on February 14. The combination of high load and increasing unplanned generating unit outages caused ERCOT's Physical Responsive Capability to drop below acceptable levels, and at

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[19] All temperatures will be in Fahrenheit unless otherwise stated.

[20] A shut-in well is a well that has been shut off so that no natural gas is flowing or being produced. *See* American Gas Association (AGA) Natural Gas Glossary, at https://www.aga.org/natural-gas/glossary/, "Shut-In" and "Shut-In Well" definitions. Some entities performed pre-emptive shut-ins to protect components from freezing, which resulted in well outages.

[21] See sidebar on Pipeline Communications on page 71.

[22] Mike Kopalek & Emily Geary, February 2021 weather triggers largest monthly decline in U.S. natural gas production, Today In Energy (May 10, 2021) https://www.eia.gov/todayinenergy/detail.php?id=47896

[23] Modeled data provided by IHS (www.ihsmarkit.com/index.html).

12:15 a.m., it issued the first stage of an Energy Emergency Alert (EEA),[24] EEA 1, which allowed it to deploy demand response resources.

Beginning in the early hours of February 15 at approximately 12:18 a.m., the ERCOT Interconnection frequency,[25] which measures the balance of supply and demand on the BES and is thus a critical indicator of BES reliability status, began to fall below the normal band level. At first ERCOT was able to recover its frequency to normal levels through deployment of load management measures, but it continued to suffer generating unit outages and needed to order its first 1,000 MW of load shed at 1:20 a.m. As system frequency continued to fall, ERCOT BA operators ordered an additional 1,000 MW of load shed, but generating units continued to fail and frequency declined to the point that ERCOT operators had only nine minutes to prevent approximately 17,000 MW of generating units from tripping due to underfrequency relays, which could potentially cause a complete blackout of the ERCOT Interconnection. ERCOT system frequency eventually bottomed out, and finally rose above the generator trip level after remaining below for over four minutes. However, unplanned generating outages continued, and ERCOT system operators continued to shed firm load to balance demand against the massive generating unit losses. For over two days, including generating units already on planned or unplanned outages when the Event began as well as unplanned outages that began during the Event, ERCOT averaged 34,000 MW of generation outages (based on expected capacity). To balance ERCOT's load against those staggering generation losses, ERCOT operators continued to order firm load shed, lasting nearly three consecutive days, and peaking at 20,000 MW by 7 p.m. on February 15.

SPP and MISO in the Eastern Interconnection also faced challenges balancing rising load with rapidly decreasing generation. SPP averaged 20,000 MW of generation unavailable (based on expected capacity) for over four consecutive days, from February 15 to 19, and MISO South averaged 14,500 MW of generation unavailable for two consecutive days, from February 16 to 18. As a result, each had its own energy and transmission emergencies, starting on February 15. Unlike ERCOT, which can only import slightly more than 1,000 MW over its direct current ties, SPP and MISO imported power from other Balancing Authorities to make up for their increasing load levels and generation shortfalls, because the eastern part of the Eastern Interconnection did not have the same arctic weather conditions. Specifically, MISO was able to import large amounts of power from neighbors to the east (e.g. PJM Interconnection, LLC), and SPP was able to transfer some of that power through MISO. Those east-to-west transfers into MISO peaked at nearly 13,000 MW on February 15. The heavy transfers, combined with the widespread generation outages, created local and system-wide transmission emergencies on February 15 and 16, which required MISO operators to order a combined 2,000 MW of firm load shed (non-coincident). On the same days, SPP experienced transmission emergencies on a system-wide basis, although they did not result in any firm load shed. SPP ordered shed firm load on February 15 and 16 for energy emergencies for a total of over four hours spread over the two days, reaching 2,718 MW at its worst point following MISO's curtailment SPP's import power due to MISO's transmission emergency. On the evening

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[24] See Appendix K for a description of the levels of alerts and Energy Emergencies.

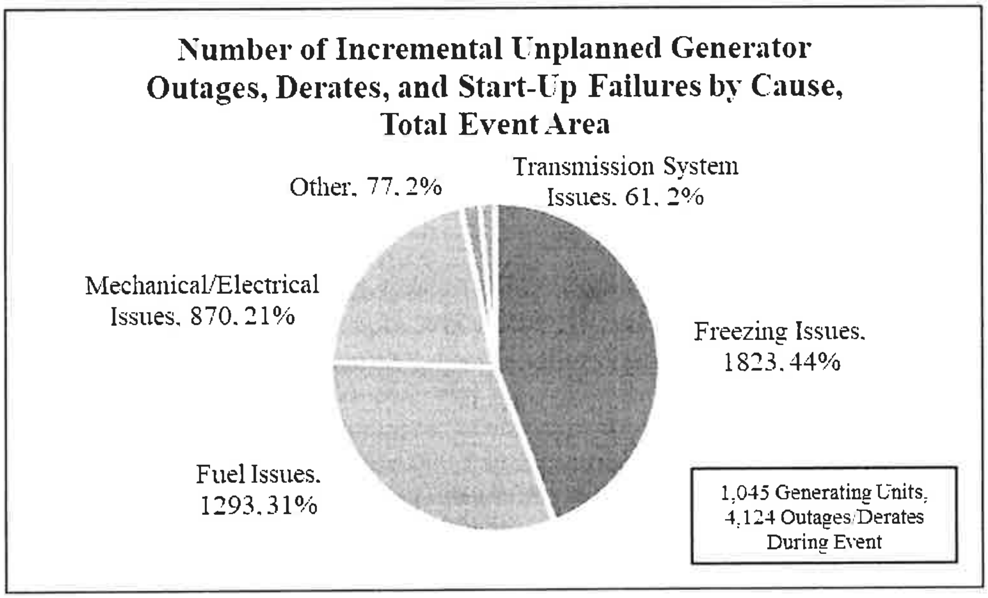
[25] Interconnection frequency is measured in Hertz (Hz). *See* NERC Glossary of Terms, Actual Frequency.

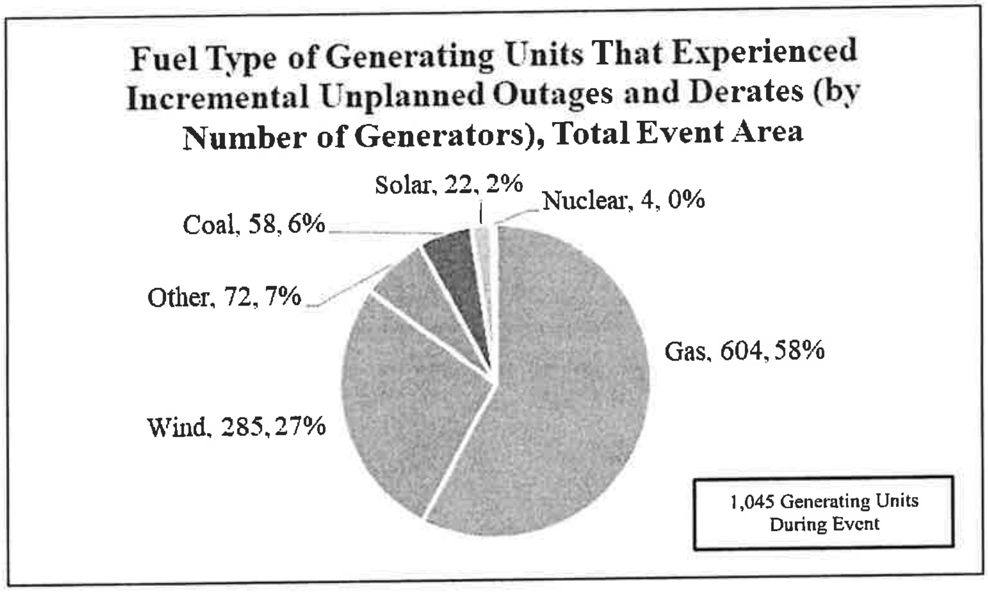
of February 16, MISO ordered firm load shed that lasted over two hours, reaching 700 MW at its worst point for an energy emergency in MISO South.

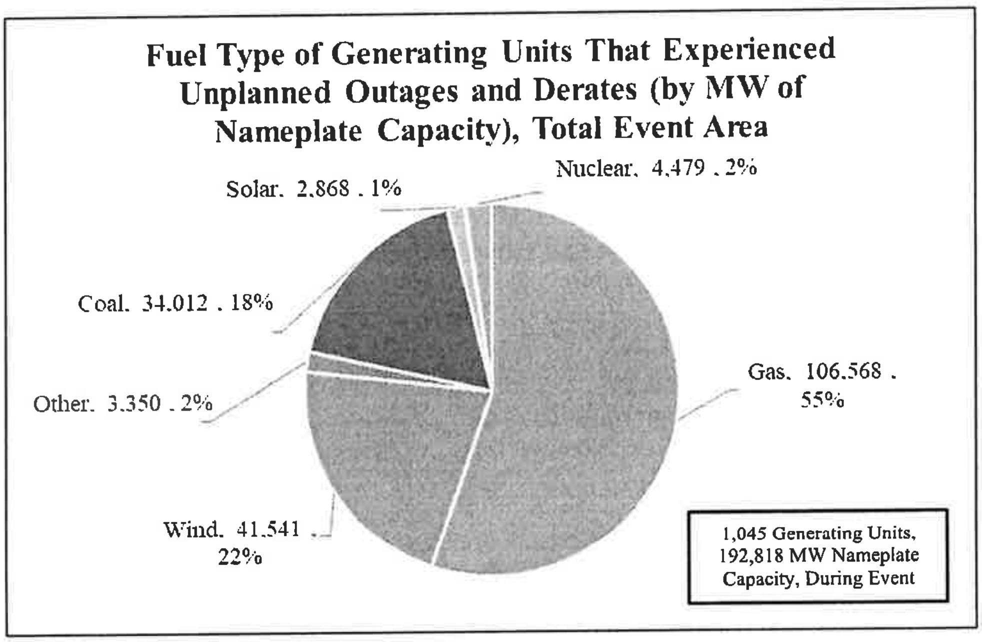
B. Key Findings and Causes

From February 8 through 20, in the Event Area, a total of 1,045 individual generating units—58 percent natural gas-fired, 27 percent wind, six percent coal, two percent solar, seven percent other fuels, and less than one percent nuclear—experienced 4,124 outages, derates or failures to start. Of those outages, derates, and failures to start, 75 percent were caused by either freezing issues (44.2 percent) or fuel issues (31.4 percent), as shown in Figure 3, below.

Figure 3: Incremental Unplanned Generating Unit Outages, Derates and Failures to Start, Total Event Area: by Cause, by Fuel Type, and by MW of Nameplate Capacity



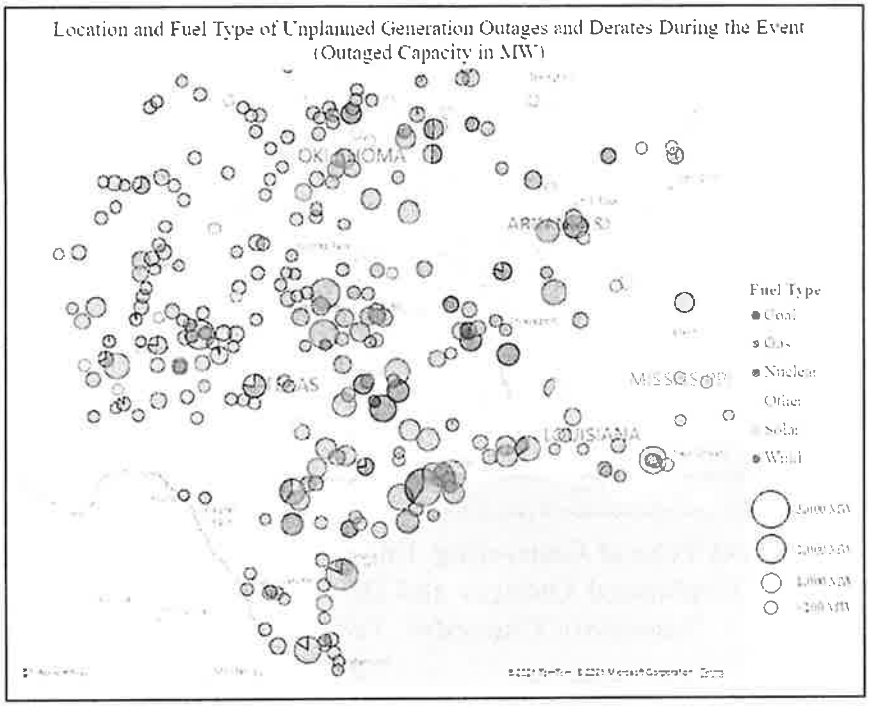




Natural gas fuel supply issues caused the majority, 87 percent, of the 31.4 percent of outages and derates due to fuel issues, and caused 27.3 percent of all outages, derates and failures to start during the Event.

In addition to the 44.2 percent of outages and derates caused by freezing issues, the 21 percent caused by "mechanical/electrical issues" also indicated a relationship with the cold temperatures—as temperatures decreased, the number of generating units outaged or derated due to mechanical/electrical issues increased. Figure 4, below depicts the locations of the generation outages, derates and failures to start during the Event.

Figure 4: Location and Fuel Type of Unplanned Generation Outages and Derates During the Event (Outaged Capacity in MW)



Despite multiple prior recommendations by FERC and NERC, as well as annual reminders via Regional Entity workshops, that generating units take actions to prepare for the winter (and providing detailed suggestions for winterization),[26] 49 generating units in SPP (15 percent, 1,944 MW of nameplate capacity), 26 in ERCOT (7 percent, 3,675 MW), and three units in MISO South (four percent, 854 MW), still did not have any winterization plans, and 81 percent of the freeze-related generating unit outages occurred at temperatures above the unit's stated ambient design temperature. Generating units that experienced freeze-related outages above the unit's stated ambient design temperature represented about 63,000 MW of nameplate capacity.

[26] 2011 Report, Recommendations 11, 14-19 https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf, 2018 Report, Recommendation 1 https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf.

C. Recommendations

Key Recommendations[27]. In response to the continued failures of generating units due to freezing issues, the Team recommends revising the mandatory Reliability Standards to require:

- Generator Owners (GOs) to identify and protect cold-weather-critical components (1a and 1b);
- GOs to retrofit existing generating units, and when building new generating units, to operate to specific ambient temperatures and weather based on extreme temperature and weather data, and account for effects of precipitation and cooling effect of wind (1f);
- GOs/ Generator Operators (GOPs) to perform annual training on winterization plans (1e);
- GOs that experience freeze-related outages to develop Corrective Action Plans (1d);
- GOs/GOPs to provide the BA with the percentage of the total generating unit capacity that the BA can rely upon during the "local forecasted cold weather" (1g); and
- GOs to account for effects of precipitation and accelerated cooling effect of wind when providing temperature data to BAs (1c).

In addition to revising the Reliability Standards, the Team also recommends that GOs have the opportunity to be compensated for the costs of retrofitting their generating units to perform at specified ambient temperatures (or designing any new units to do so) (2); that FERC, NERC and the Regional Entities host a joint technical conference to discuss how to improve the winter readiness of generating units before the recently-approved Reliability Standards revisions[28] become effective (3); and that GOs'/GOPs' freeze protection plans include certain times for inspection and maintenance (e.g., before and after winter and before specific cold weather events) (4).

Regarding natural gas fuel issues, the second largest cause of the generating unit outages, the Team recommends that Congress, state legislatures and regulatory agencies with jurisdiction over natural gas infrastructure facilities require those natural gas facilities to implement and maintain cold weather preparedness plans (5); that natural gas infrastructure facilities undertake voluntary measures to prepare for cold weather (6); and that GOs/GOPs identify the reliability risks related to their natural gas fuel contracts so that they can provide the BAs with the percentage of total generating unit capacity that the BA can rely upon during the "local forecasted cold weather" (8). To address the recurring challenges stemming from natural gas-electric infrastructure interdependency, as shown in part by Figure 5 below,[29] the Team recommends that FERC consider establishing a forum

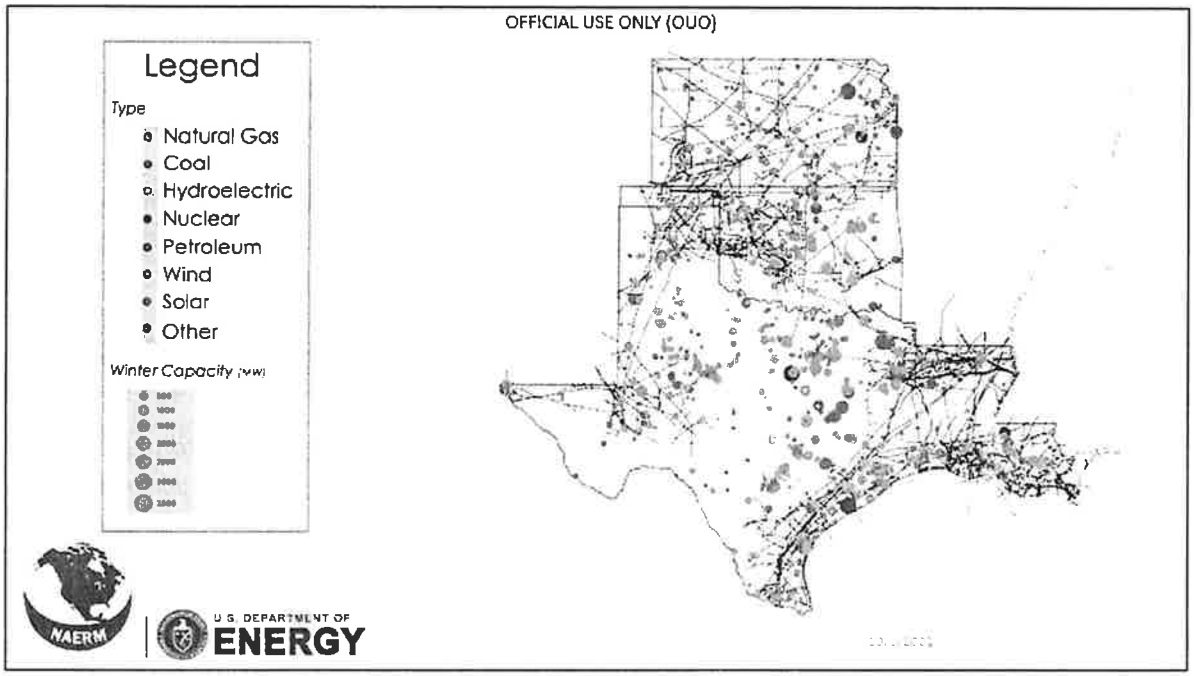
[27] Each Recommendation number is in parentheses after the summary of the Recommendation.

[28] In August, the Commission approved revisions to the NERC Reliability Standards to address cold weather, including a new requirement for generating units to have a cold weather preparedness plan. However, the effective date for these revisions is April 1, 2023. See 176 FERC ¶ 61,119 (August 2021).

[29] Figure 5, used by permission of the Department of Energy, shows the locations of both electric generating units, and the interstate natural gas pipelines available to deliver fuel to natural gas-fired generating units. The Team thanks the

to identify concrete actions to improve the reliability of the natural gas infrastructure system[30] necessary to support the BES (7).

Figure 5: Interdependency of Electric and Natural Gas Infrastructure, South Central U.S., and Texas



The Team also recommends three additional revisions to the Reliability Standards: to protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting BES reliability (1i); to require Balancing Authorities' operating plans to prohibit use of critical natural gas infrastructure loads for demand response (1h); and to separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS) and use the UFLS circuits only as a last resort (1j).

<u>Other Recommendation Areas</u>. In addition to the Reliability Standards revisions, the Team makes recommendations in areas including seasonal reserve margin calculations (9), effects of cold weather on mechanical fatigue (11), increasing the flexibility of manual load shedding (10), GO/GOP use of weather forecasts (12), coordination of protective relay settings associated with generator underfrequency relays (13), coordination of UFLS relay settings with generating unit time-delay

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Department of Energy for sharing its North American Electric Resilience Model (NAERM). The NAERM is intended to bring together models of multiple types of infrastructure in the United States, such as natural gas, electric, telecommunications, water, etc., and simulate various contingencies. DOE used the NAERM to prepare Figure 5 and the NAERM was helpful to the Team in understanding interdependencies between the natural gas infrastructure and bulk-electric systems.

[30] "Natural gas infrastructure" refers to natural gas production, gathering, processing intrastate and interstate pipelines, storage and other infrastructure used to move natural gas from wellhead to burner tip.

protection systems (22), increasing real-time monitoring of gas wellheads (14), emergency response centers for severe weather events (15), improving near-term load forecasts for extreme weather conditions (16), analyzing intermittent generation effects to improve load forecasts (17), rapidly-deploying demand response (18), additional load shed training for system operators (21), retail incentives for energy efficiency improvements (19), reducing the time for generation and transmission outages to be reported (23), and studies of large power transfers during stressed conditions (20). Finally, the Team recommends additional study in five areas: black start unit reliability (26), additional ERCOT connections to other interconnections (25), potential measures to address natural gas supply shortfalls (24), potential effects of low-frequency events on generators in the Western and Eastern Interconnections (27), and guidelines for identifying critical natural gas infrastructure loads (28).

NEWS RELEASES

FERC, NERC Staff Review 2021 Winter Freeze, Recommend Standards Improvements

September 23, 2021
Docket No. AD21-28
Item: A-3 | Staff Presentation | PPT

The electric and natural gas industries need to strengthen their winterization and cold weather preparedness and coordination to prevent a recurrence of the unprecedented February 2021 power outages to millions of people during the February 2021 freeze in Texas and the Midwest.

That is the assessment of a preliminary report presented at today's Federal Energy Regulatory Commission (FERC) meeting by a joint inquiry team of staff from FERC and the North American Electric Reliability Corporation (NERC) and its regional entities. The report reviews what happened during the freeze and outlines a series of recommendations, including mandatory electric reliability standards, to prevent its recurrence.

> "This is a wake-up call for all of us. There was a similar inquiry after Texas experienced extreme cold weather in 2011, but those recommendations were not acted on," FERC Chairman Rich Glick said. "We can't allow this to happen again. This time, we must take these recommendations seriously, and act decisively, to ensure the bulk power system doesn't fail the next time extreme weather hits. I cannot, and will not, allow this to become yet another report that serves no purpose other than to gather dust on the shelf."

> "These preliminary findings provide clear and comprehensive insight into what happened on the grid during the February freeze and our joint recommendations provide a roadmap for what actions need to be taken next in order to prevent a repeat occurrence," said Jim Robb, president and CEO of NERC. "Our coordinated efforts – across both the electric and natural gas industries – will provide the way ahead. NERC and FERC are committed to working together to make this happen."

The February freeze triggered the loss of 61,800 megawatts of electric generation, as 1,045 individual generating units experienced 4,124 outages, derates or failures to start. It severely reduced natural gas production, with the largest effects felt in Texas, Oklahoma and Louisiana, where combined daily

Mary O'Driscoll
Director, Media Relations

Telephone: 202-502-8680
Email: mediadl@ferc.gov

Kimberly Mielcarek, NERC
Email: Kimberly.mielcarek@nerc.net

This page was last updated on September 23, 2021

APPENDIX NO. 15
FERC, ORDERS
NO. 831
NO. 2000

89 FERC ¶ 61,285

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM99-2-000; Order No. 2000]

Regional Transmission Organizations

(Issued December 20, 1999)

AGENCY: Federal Energy Regulatory Commission

ACTION: Final Rule

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations under the Federal Power Act (FPA) to advance the formation of Regional Transmission Organizations (RTOs). The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO. The Commission also codifies minimum characteristics and functions that a transmission entity must satisfy in order to be considered an RTO. The Commission's goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service.

EFFECTIVE DATE: This Final Rule will become effective [on the 60th day after publication in the Federal Register.]

157 FERC ¶ 61,115
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM16-5-000; Order No. 831]

Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators

(Issued November 17, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission is revising its regulations to address incremental energy offer caps. We require that each regional transmission organization (RTO) and independent system operator (ISO): (1) cap each resource's incremental energy offer at the higher of $1,000/megawatt-hour (MWh) or that resource's verified cost-based incremental energy offer; and (2) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices (LMP). Further, we clarify that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs. This Final Rule will improve price formation by reducing the likelihood that offer caps will suppress LMPs below the marginal cost of production, while compensating resources for the costs they incur to serve load, by enabling RTOs/ISOs to dispatch the most efficient set of resources when

APPENDIX NO. 16

FERC, Filing Materials \for SPP membership

September 30, 2008

For

Membership effective

April 1, 2009

ATTORNEYS AT LAW

WRIGHT & TALISMAN, P.C.

1200 G Street, N.W.
Suite 600
Washington, D.C. 20005-3802
202-393-1200
FAX 202-393-1240
www.wrightlaw.com

September 30, 2008

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: ***Southwest Power Pool, Inc.*, Docket No. ER08-____-000**
Revisions to Bylaws, Tariff, and Membership Agreement

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Part 35 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. Part 35, Southwest Power Pool, Inc. ("SPP"), as authorized by its Board of Directors, proposes amendments to its Bylaws, Open Access Transmission Tariff ("Tariff"), and Membership Agreement. SPP proposes the amendments in order to facilitate Nebraska Public Power District ("NPPD"), Omaha Public Power District ("OPPD"), and Lincoln Electric System ("LES") (collectively the "Nebraska Entities") becoming Members of SPP. SPP requests that these revisions be made effective December 1, 2008.

I. BACKGROUND

A. Identity of SPP and the Nebraska Entities

SPP is a Commission-approved Regional Transmission Organization ("RTO"). It is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP currently has 50 Members, serving more than 4 million customers in a 255,000 square-mile area covering all or part of eight states. SPP's members include 12 investor-owned utilities, 8 municipal systems, 11 generation and transmission cooperatives, 2 state authorities, 4 independent power producers, 11 power marketers, and 2 independent transmission companies. As an RTO, SPP is a transmission provider administering transmission service over portions of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas. In addition to providing tariff services as an RTO, SPP serves as a "Regional Entity" for the North American Electric Reliability Corporation.[1]

NPPD is a publicly-owned electric utility and political subdivision of the state of Nebraska. It is not a public utility as defined by the Federal Power Act.[2] Pursuant to Nebraska statutes, NPPD is engaged in the generation, transmission, and delivery of electric power and energy to wholesale and retail customers throughout the state of Nebraska. NPPD is Nebraska's largest electric utility, with over 4,300 miles of transmission lines and a peak load of approximately 2,600 MW within a chartered territory including all or parts of 91 of Nebraska's 93 counties. It serves approximately 88,000 retail customers throughout the state and serves the wholesale requirements of 78 municipalities, public power districts, and cooperatives. In total, NPPD directly or indirectly provides energy and transmission service to approximately 1,000,000 Nebraskans. NPPD is governed by an independent 11-member Board of Directors popularly elected from NPPD's chartered territory.

OPPD is a publicly-owned electric utility and political subdivision of the state of Nebraska. It is not a public utility as defined by the Federal Power Act.[3] With a peak load of approximately 2,200 MW, OPPD serves more than 340,000 customers in 13 eastern Nebraska counties, including the Omaha, Nebraska metropolitan area. It was organized as a political subdivision of the State of Nebraska in 1946 and is governed by an eight-member Board of Directors elected by the people in its service territory.

LES is a municipal electric utility formed in 1966 that now serves approximately 108,000 residential customers and 15,000 commercial and industrial customers located in Lancaster County, Nebraska, including the cities of Lincoln, Prairie Home, Waverly, Walton, Cheney, and Emerald. LES is a non-profit, customer-owned utility governed by a semi-autonomous administrative board of local citizens. LES is not a public utility as defined by the Federal Power Act.[4]

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1 *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

2 16 U.S.C. § 824(e).

3 *Id.*

4 *Id.*

Omaha Public Power District

444 South 16th Street Mall
Omaha NE 68102-2247

November 7, 2008

SPP Regional Entity Manager
Charles Yeung
415 North McKinley Street Suite 140
Little Rock, AR 72205

Dear Mr. Yeung:

The Omaha Public Power District (OPPD) has filed with FERC to join Southwest Power Pool, Inc. and upon FERC approval will be receiving Regional Transmission Organization services effective April 1, 2009, including being under the authority of the SPP reliability coordinator. As a result of the transition, OPPD is requesting to move our current Registration for compliance and enforcement of North American Electric Reliability Corporation standards for bulk power system reliability from the MRO to the authority of the SPP Regional Entity (SPP RE).

To effectuate this transfer of Registration, we request that the SPP RE make the necessary changes to its Regional Entity Delegation Agreement with NERC so that OPPD will be registered in the SPP RE footprint. We also understand that NERC and the SPP RE will need to revise its billing for reliability services and we are providing our 2007 Net Energy for Load data on the attached completed NEL data submittal form. Finally, we recognize that such changes between NERC and SPP, and NERC and the MRO will need to be accepted by the FERC, and that SPP, Inc. will work with NERC to make such appropriate regulatory filings.

As a matter of consistency and to avoid duplication we have requested that the Midwest Reliability Organization, who currently provides the RE services for us, update its Regional Entity Delegation Agreement and any relevant filings to reflect this change.

Please make all the necessary changes so that OPPD will begin taking SPP RE services on April 1, 2009

Sincerely,

David Ried
Division Manager
Energy Marketing and Trading

DGR:DLC

Encl.

c: Dan Skaar, MRO
Carl Monroe, SPP
Dale Widoe, OPPD
Blaine Dinwiddie, OPPD

SOUTHWEST POWER POOL
Assessment Information Form

Company Name:	Omaha Public Power District
Date:	30-Oct-08
Your Name:	David G. Ried
Your Phone #:	402-514-1025

2007 NET ENERGY FOR LOAD (MWh)

Definition : The electrical energy requirements of an electric system are defined as system net generation plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage at energy storage facilities. (As defined in Section 1.10 of the SPP Bylaws).

Purpose: For NERC Annual Assessment.

INSTRUCTIONS:
For Balancing Authorities
1. Enter the Net Energy for Load (NEL) Total for your Control Area - Section 1
2. Enter the Net Energy for Load (NEL) for your company and each LSE by Control Area - Section 2
3. Subtotals in Section 1 and Section 2 should equal by Control Area
4. Totals in Section 1 and Section 2 should equal

For LSE's:
1. Enter the Net Energy for Load (NEL) for each Control Area where your company serves load - Section 2

Section 1 - Net Energy for Load (MWh) - Control Area Totals

Control Area	Net Energy for Load
OPPD	11,110,236

Section 2 - Net Energy for Load (MWh) - LSE Subtotals

NERC ID	Control Area	LSE Name	Net Energy for Load
1232	OPPD	OPPD	10,585,160
1205	OPPD	FCU	38,267
1206	OPPD	Fremont	448,542
1229	OPPD	NCU	38,267

Nebraska Public Power District

"Always there when you need us"

Patrick L. Pope
Vice President & Chief Operating Officer
(402) 563-5029 / 5145 fax
plpope@nppd.com

November 21, 2008

SPP Regional Entity Manager
Charles Yeung
415 North McKinley St., Suite 140
Little Rock, AR 72205

Dear Mr. Yeung:

Nebraska Public Power District (NPPD) is joining the Southwest Power Pool (SPP), Inc, contingent upon FERC approval, and plans to start receiving SPP Regional Transmission Organization services effective April 1, 2009 including being under the authority of the SPP Reliability Coordinator. As a result of the transition, NPPD is requesting to move our current Registration for compliance and enforcement of the North American Electric Reliability Corporation (NERC) standards for bulk power system reliability from the Midwest Reliability Organization (MRO) to the authority of the SPP Regional Entity (SPP RE).

To effectuate this transfer of Registration, we request that the SPP RE make the necessary changes to its Regional Entity Delegation Agreement with NERC so that NPPD will be registered in the SPP RE footprint. We also understand that NERC and the SPP RE will need to revise its billing for reliability services and we are providing our 2007 Net Energy for Load data on the attached completed NEL data submittal form. Finally, we recognize that such changes between NERC and SPP, and NERC and the MRO will need to be accepted by the FERC, and that SPP Inc. will work with NERC and MRO to make such appropriate regulatory filings.

By copy of this letter to the MRO, as a matter of consistency and to avoid duplication, we are requesting that the MRO who currently provides the RE services for NPPD, update its Regional Entity Delegation Agreement and any relevant filings to reflect this change.

Please make all the necessary changes so that NPPD can begin taking SPP RE services on April 1, 2009.

Sincerely,

Patrick L. Pope
Vice President &
Chief Operating Officer

cc: Daniel P. Skaar, President, MRO

SOUTHWEST POWER POOL
Assessment Information Form

Company Name:	Nebraska Public Power District
Date:	11/21/2008
Your Name:	Rick Koch
Your Phone #:	402-845-5210

2007 NET ENERGY FOR LOAD (MWh)

Definition : The electrical energy requirements of an electric system are defined as system net generation plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage at energy storage facilities. (As defined in Section 1.10 of the SPP Bylaws).

Purpose: For NERC Annual Assessment.

INSTRUCTIONS:
For Balancing Authorities
1. Enter the Net Energy for Load (NEL) Total for your Control Area - Section 1
2. Enter the Net Energy for Load (NEL) for your company and each LSE by Control Area - Section 2
3. Subtotals in Section 1 and Section 2 should equal by Control Area
4. Totals in Section 1 and Section 2 should equal

For LSE's:
1. Enter the Net Energy for Load (NEL) for each Control Area where your company serves load - Section 2

Section 1 - Net Energy for Load (MWh) - Control Area Totals

Control Area	Net Energy for Load
NPPD	Not Available

Section 2 - Net Energy for Load (MWh) - LSE Subtotals

Control Area	LSE Name	Net Energy for Load
NPPD	NPPD	Not Available
OPPD	NPPD	Not Available
WAPA RM	NPPD	Not Available
WAPA UGP	NPPD	Not Available
Total All CA's	NPPD	12,394,564

Exhibit A

Coordination Guidelines for Nebraska Entities and Southwest Power Pool, Inc. (as the Registered Entity) in MRO Region

June 11, 2010

Background

On April 19, 2007, the Federal Energy Regulatory Commission ("Commission" or "FERC") issued an order accepting Delegation Agreements between the North American Electric Reliability Corporation (NERC) and eight Regional Entities (REs), including the Midwest Reliability Organization (MRO) and Southwest Power Pool, Inc. (SPP) Regional Entity division[13]. In each Delegation Agreement, NERC assigned authority to the RE to, among other things, enforce compliance with Reliability Standards within the geographic boundaries set forth in Exhibit A of the RE's Delegation Agreement.

Geographic boundaries of the Regional Entities were generally established based upon the existing boundaries of the predecessor organizations (Regional Reliability Councils), which were somewhat based on the topography of the bulk electric system and the operating footprints of the membership within the voluntary regional reliability organizations. These geographic areas were generally the basis for regional bulk power system planning, modeling, and system analyses, as well as for other types of regional planning and operational coordination such as UFLS programs and system restoration plans. MRO geography includes the former MAPP region, parts of the former MAIN region and Saskatchewan (which was not part of a predecessor organization). In the future, tasks such as these would likely be re-assigned to Planning Coordinators and/or Reliability Coordinators, but currently are included in the responsibilities of the Regional Entities (as part of the so called "fill in the blank" standards).

As a condition of the Delegation Agreement, each RE also had to agree to comply with the provisions within the NERC Rules of Procedure (ROP). The ROP provides for additional activities such as Organizational Registration and Certification, Reliability Readiness Audit and Improvement, Reliability Assessment and Performance Analysis, Training and Education, and Situational Awareness and Infrastructure Security.

Nebraska area changes

On April 1, 2009, Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), and Lincoln Electric System (LES) ("Nebraska entities") joined SPP and began to take Reliability Coordinator (RC) and tariff administration services from SPP. On March 26, 2009, MRO approved the revised Reliability plan for SPP Regional Transmission Organization (RTO), which included the Nebraska entities. In addition, certain Nebraska utilities requested to move their RE affiliation from MRO to SPP (as administered by the SPP Regional Entity division). These requests to move registration remain pending with MRO, SPP RE division and NERC.

[13] This document refers to SPP in two contexts. One, SPP, as the Regional Entity under Section 215 of the Federal Power Act or "SPP RE division. Two, SPP, as a Registered Entity in both SPP RE division and MRO geographies or "SPP RTO".

Coordination Guidelines

While the requests to move RE registration from MRO to the SPP RE division remain pending, the Nebraska entities and the SPP RTO will operate in accordance with these Coordinating Guidelines to ensure clarity for Nebraska entities and SPP RTO to avoid duplication where possible and provide certainty for regional delegated authorities between MRO and SPP RE division and those subject to the standards under Section 215 of the Federal Power Act.

Model Building

The bulk power systems of NPPD, OPPD, and LES will be included in the models of SPP as their Planning Coordinator. Staff of MRO will coordinate the timing of data collection and other modeling details to ensure the seams are clear in the models and minimize duplication with the cooperation from the Nebraska entities and SPP RTO.

The Nebraska entities will submit their respective modeling data directly to SPP RTO for the 2010 model series. The MRO Model Building Subcommittee may choose whether to obtain these updates as a part of the MMWG external model or directly from SPP RTO for use in the MRO 2010 series models so that the Nebraska entities will only need to submit their data once (to SPP).

Seasonal and Long Term Assessments

Bulk power system planning for the Nebraska entities will be coordinated by SPP RTO as their Planning Authority (PA), using the appropriate planning criteria, processes and models for the NERC 2010 seasonal assessments, scenario assessments, and LTRA. SPP RTO, as the PA, will continue to perform appropriate studies to meet the requirements for TPL-001 to TPL-004.

The Nebraska entities will submit their respective data and narrative portions of these assessments to MRO. The Nebraska entities will complete the NERC spreadsheet for their respective company's load, generation, interchange, transmission, energy, etc., and return it to MRO. MRO will include the Nebraska entities in their regional assessment submittals to NERC. This does not prohibit or limit the Nebraska entities from voluntary participation in the SPP RE division assessment process in 2010 (as they have expressed a desire to do so).

For assessments, MRO has proposed to NERC that assessments should be conducted on planning authority geographies which would resolve the matter for all parties.

Periodic Data Reporting

These periodic data requirements will be collected/performed by MRO:

- CPS data, for analysis and subsequent reporting to NERC
- Relay mis-operations
- Reviews of new or modified SPSs and periodic reviews of an SPS
- Frequency bias settings
- Monthly Operator Credentials (PER-003)
- Ongoing and Quarterly Vegetation related transmission outages
- Annual Self-Certification

- Exception reporting identified in the annual implementation plan
- NERC GADS and TADS data submittals
- Quarterly updates required by NERC EOP-005-1 for the exercise, drill, and simulation of restoration of offsite power to nuclear stations

DCS data will be submitted to SPP RTO (through its Reserve Sharing Group) for compilation and reporting to NERC, with a copy of the report provided to MRO.

Additional Clarifications on Requirements for Nebraska entities and SPP RTO

- MRO will monitor compliance and handle enforcement for violations of all regulatory approved Reliability Standards and is the Compliance Enforcement Authority for the Nebraska entities and the applicable parts of the SPP RTO.
- Contingency reserve requirements for NPPD, OPPD, and LES will be those established by SPP RTO until a NERC standard is established and mandatory. Black Start coordination is the responsibility of SPP RTO as the Reliability Coordinator.
- For generator testing, he Nebraska entities should select the criteria that are most consistent with maintaining reliability in their respective areas and report their respective selections to MRO until a mandatory standard is established by NERC.
- Event Analysis coordination will be determined by the circumstances. In general, a wide spread event will be coordinated by NERC. A more localized event will be coordinated based upon the circumstances. MRO and SPP RE division will coordinate appropriately.
- The designated Planning Authority for the Nebraska entities is SPP RTO.
- The designated Transmission Service Provider for the Nebraska entities is SPP RTO.
- For Disturbance Monitoring Equipment requirements, the Nebraska entities should select the criteria that are most consistent with maintaining reliability in their respective areas and report their respective selections to MRO until a mandatory standard is established by NERC.
- For Under Frequency Load Shed and Under Voltage Load Shed programs, the Nebraska entities should select the criteria that are most consistent with maintaining reliability in their respective areas and report their respective selections to MRO until a mandatory standard is established by NERC.

Regional Standards

MRO and SPP RE division will determine the applicability of any new or revised Regional Standards for Nebraska entities and SPP RTO consistent with maintaining reliability in the area.

Exhibit B

NERC's entire Assessment Schedule for 2011 can be found by following:
http://www.nerc.com/docs/bot/finance/Appendix_2_AssessmentCalculations.pdf

2011 Budget and Assessment Impacts

	MRO NEL	MRO NEL Pct	MRO Budget Amt	SPP NEL	NEL	SPP Budget Amt	Increase/(Decr)
NPPD	12,666,632	4.784%	$ 389,006	12,666,632	5.578%	$ 546,515	$ 157,509
OPPD	10,305,544	3.893%	$ 316,495	10,305,544	4.538%	$ 444,644	$ 128,149
Grand Island	681,421	0.257%	$ 20,927	681,421	0.300%	$ 29,401	$ 8,473
Hastings Utilities	395,028	0.149%	$ 12,132	395,028	0.174%	$ 17,044	$ 4,912
NE Entities	24,048,625	9.083%	$ 738,560	24,048,625	10.591%	$ 1,037,604	$ 299,044

	MRO NEL	MRO NEL Pct	MRO Assessment Amt	SPP NEL	NEL	SPP Assessment Amt	Increase/(Decr)
NPPD	12,666,632	4.784%	$ 395,211	12,666,632	5.578%	$ 507,342	$ 112,131
OPPD	10,305,544	3.893%	$ 321,542	10,305,544	4.538%	$ 412,772	$ 91,230
Grand Island	681,421	0.257%	$ 21,261	681,421	0.300%	$ 27,293	$ 6,032
Hastings Utilities	395,028	0.149%	$ 12,325	395,028	0.174%	$ 15,822	$ 3,497
NE Entities	24,048,625	9.083%	$ 750,339	24,048,625	10.591%	$ 963,230	$ 212,891

	MRO	SPP
Total NEL	264,751,863	203,022,708
NE Entities	24,048,625	24,048,625
Revised NEL	240,703,238	227,071,333
2011 Budget	$ 8,130,824	$ 9,797,236
2011 Assessment	$ 8,260,502	$ 9,094,985

Note: Budget are operating costs plus capital costs; Assessments are net of penalties collected and other adjustments

Reference: Figures from 2011 Business Plan and Budget from SPP RE and MRO; NEL figures of NE Entities.

APPENDIX NO. 17

FERC, NERC Critical Report on February 2021 Freeze

September 29, 2021

September 29, 2021

FERC and NERC Issue Critical Report on February 2021 Freeze

Brendan Connors, F. Alvin Taylor Jr.

Holland & Knight LLP

Holland & Knight

At the open monthly meeting of the Federal Energy Regulatory Commission (FERC) on Sept. 23, 2021, a joint team composed of the staffs of FERC, the North American Electric Reliability Corporation (NERC) and NERC's various regional entities presented a preliminary report regarding the February 2021 winter storm that afflicted Texas and the Midwest.

The report analyzes the root causes of the power outages caused by the freeze and highlights the actions taken in response by the affected balancing authorities, focusing particularly on measures taken by the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO). The report then outlines certain preliminary actions it recommends that these entities take to prevent, or mitigate, the harm caused by any future, similar weather events.

In analyzing the reasons for the extended power outages caused by the freeze, the report identifies the freezing of generator components and natural gas supply shortfalls as the primary culprits. The report blames the generator freezing mainly on the failure to sufficiently "winterize" the units for cold weather conditions. In turn, it attributes the natural gas supply shortages to the combined effects of decreased natural
conditions of natural gas commodity and pipeline tran
such as low pressure. Conversely, the report concludes
coordinators effectively coordinated with one another
the grid by the freeze.

The report then makes 28 separate recommendations,
to be implemented across one of four time frames. Am

- revising reliability standards to require generator owners to identify and protect cold-weather-critical components
- forcing owners to winterize new units, or retrofit existing ones
- allowing owners to recover the costs of doing so
- requiring gas facilities to implement cold-weather preparedness plans
- hosting a joint FERC/NERC/Regional Entities technical conference to discuss how to improve generator winter readiness

Finally, the report recommends certain subjects for further study, including researching:

- black start unit availability in ERCOT during cold-weather conditions
- additional links between the ERCOT Interconnection and the Eastern, Western and/or Mexico Interconnections
- potential measures to address natural gas fuel supply shortfalls during extreme cold-weather events
- potential effects of low-frequency events on generators in the Western and Eastern Interconnections
- establishing a guideline with criteria for identifying critical natural gas infrastructure loads

A final, full version of this report will likely be released in November, so interested parties should continue to monitor FERC's actions in this arena.

RELATED POSTS

- **FERC Seeks Input on Electric Reliability Issues From Climate Ch**

LATEST POSTS

- **ANM en Colombia fija condiciones para garantías en contratos A...**

- **Proposed MEPA Regulations Leave Key Substantive Questions Unanswered**
- **FERC and NERC Issue Critical Report on February 2021 Freeze**
- **Delaware Supreme Court Adopts Universal 3-Part Test to Assess Demand Futility**

See more »

WRITTEN BY:

Holland & Knight LLP

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F. Alvin Taylor Jr. + Follow

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Information Reports

MISO

NERC

Reliability Standards

Severe Weather

APPENDIX NO. 18

How Microgrids Work

U.S. Dept. of Energy

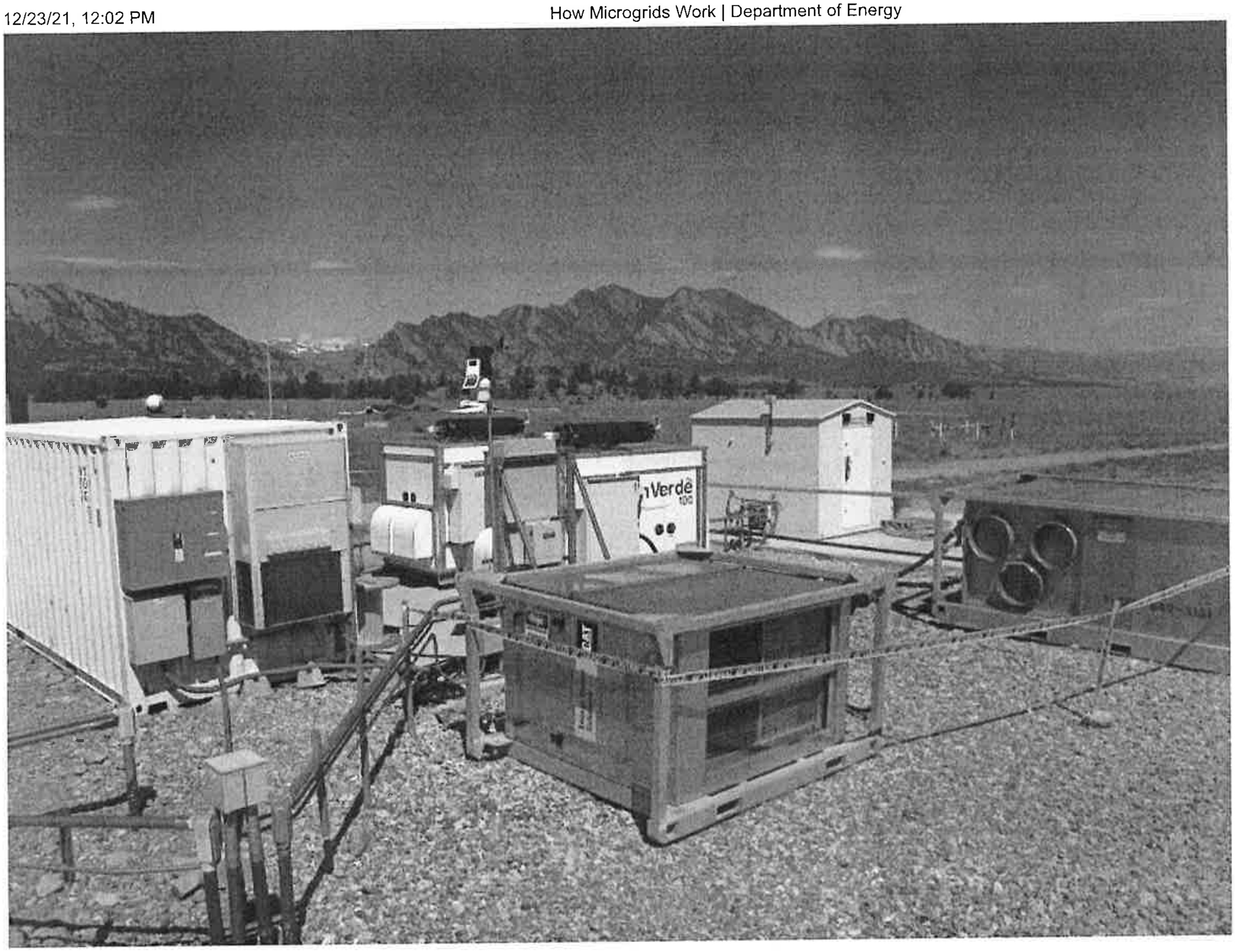
June 17, 2014

Department of Energy

How Microgrids Work

JUNE 17, 2014

Energy.gov » How Microgrids Work



Microgrid equipment at the National Wind Technology Center in Colorado. | Photo courtesy of the National Renewable Energy Lab.

This week we're celebrating the launch of a new series on Energy.gov: How Energy Works. Join us today on Twitter at 2 p.m. ET for our How Energy Works live Q&A answering everything you want to know about microgrids. Use #HowEnergyWorks to submit questions and follow the live discussion.

WHAT IS A MICROGRID?

A microgrid is a local energy grid with control capability, which means it can disconnect from the traditional grid and operate autonomously.

HOW DOES A MICROGRID WORK?

To understand how a microgrid works, you first have to understand how the grid works.

The grid connects homes, businesses and other buildings to central power sources, which allow us to use appliances, heating/cooling systems and electronics. But this interconnectedness means that when part of the grid needs to be repaired, everyone is affected.

This is where a microgrid can help. A microgrid generally operates while connected to the grid, but importantly, it can break off and operate on its own using local energy generation in times of crisis like storms or power outages, or for other reasons.

A microgrid can be powered by distributed generators, batteries, and/or renewable resources like solar panels. Depending on how it's fueled and how its requirements are managed, a microgrid might run indefinitely.

HOW DOES A MICROGRID CONNECT TO THE GRID?

A microgrid connects to the grid at a point of common coupling that maintains voltage at the same level as the main grid unless there is some sort of problem on the grid or other reason to disconnect. A switch can separate the microgrid from the main grid automatically or manually, and it then functions as an island.

WHY WOULD A COMMUNITY CHOOSE TO CONNECT TO MICROGRIDS?

A microgrid not only provides backup for the grid in case of emergencies, but can also be used to cut costs, or connect to a local resource that is too small or unreliable for traditional grid use. A microgrid allows communities to be more energy independent and, in some cases, more environmentally friendly.

HOW MUCH CAN A MICROGRID POWER?

A microgrid comes in a variety of designs and sizes. A microgrid can power a single facility like the Santa Rita Jail microgrid in Dublin, California. Or a microgrid can power a larger area. For example, in Fort Collins, Colorado, a microgrid is part of a larger goal to create an entire district that produces the same amount of energy it consumes.

Other examples of microgrids around the world are available on Berkeley Lab's example page.

WHAT OTHER RESOURCES ARE THERE?

To learn more about what the Energy Department is doing to research microgrids, you can visit the Office of Electricity's microgrid activities page.

ALLISON LANTERO

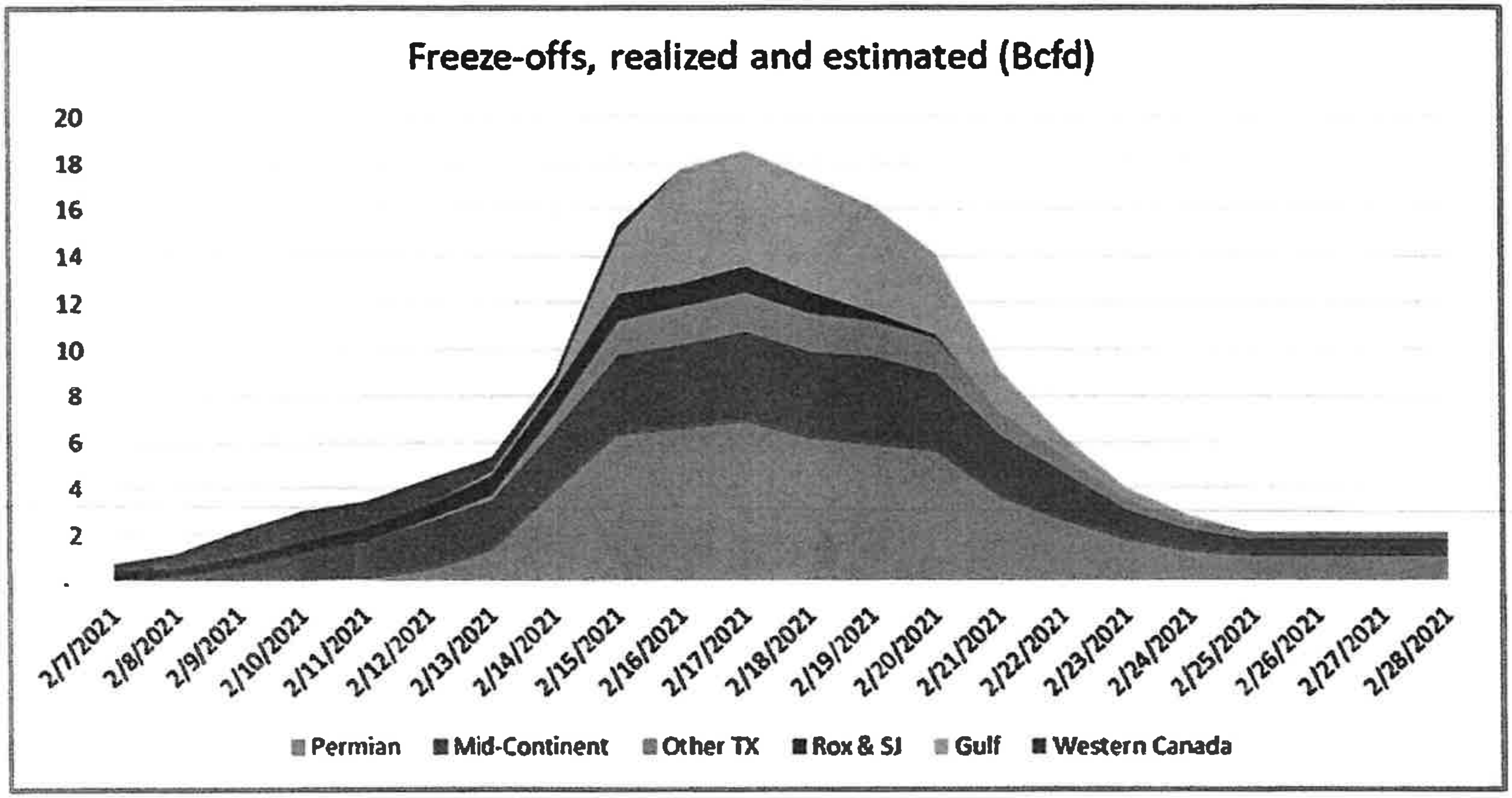
Served as Digital Content Specialist in the Office of Public Affairs.Served as Digital Content Specialist in the Office of Public Affairs.

MORE BY THIS AUTHOR

APPENDIX NO. 19
MEAN FIGURES
REPORTED
LR49 (2021) MATERIALS
MARCH 9, 2021

Available in office of Natural Resources Committee

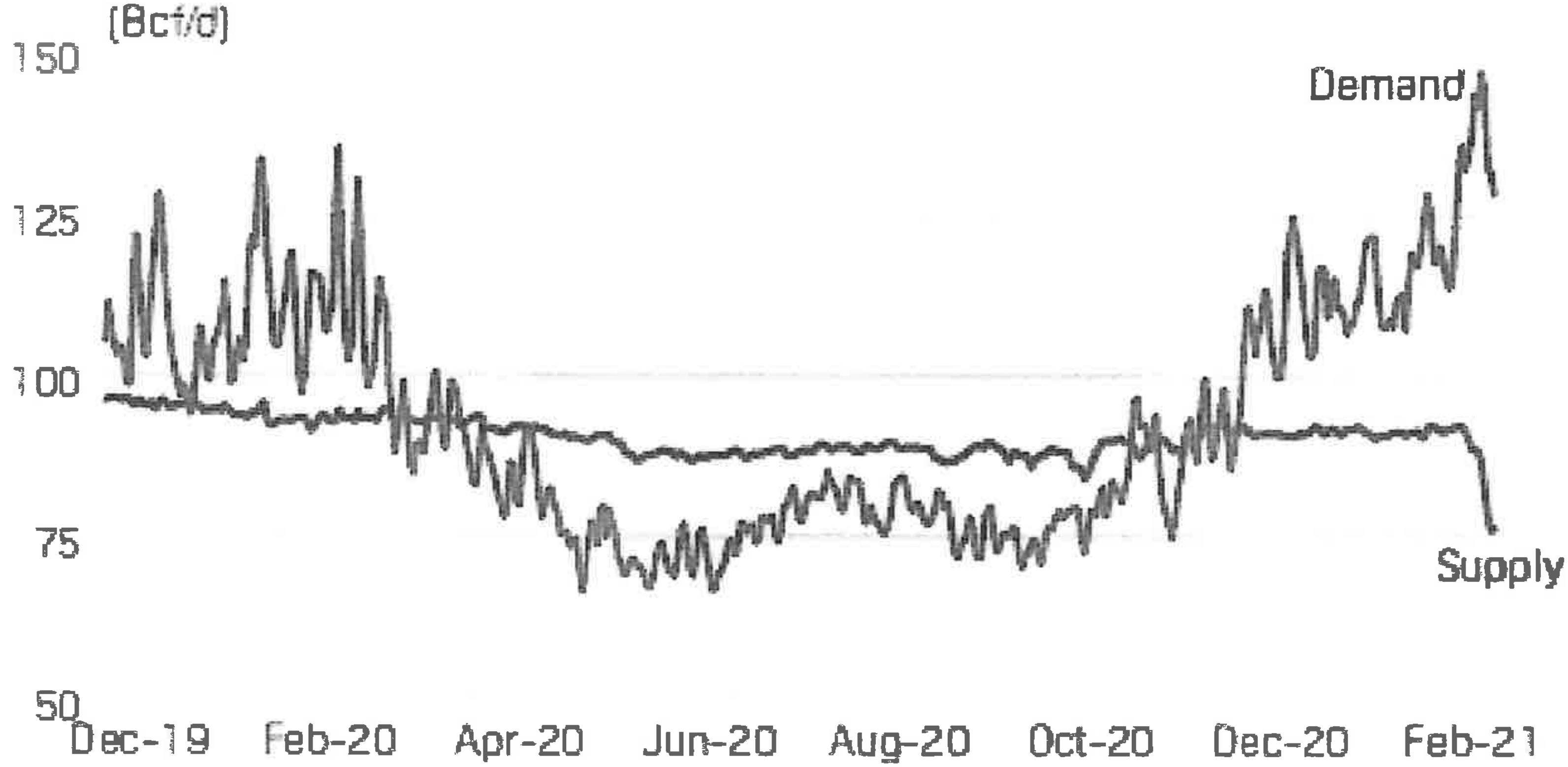
Deep Freeze in Natural Gas Supplies



** Source: Mercuria*

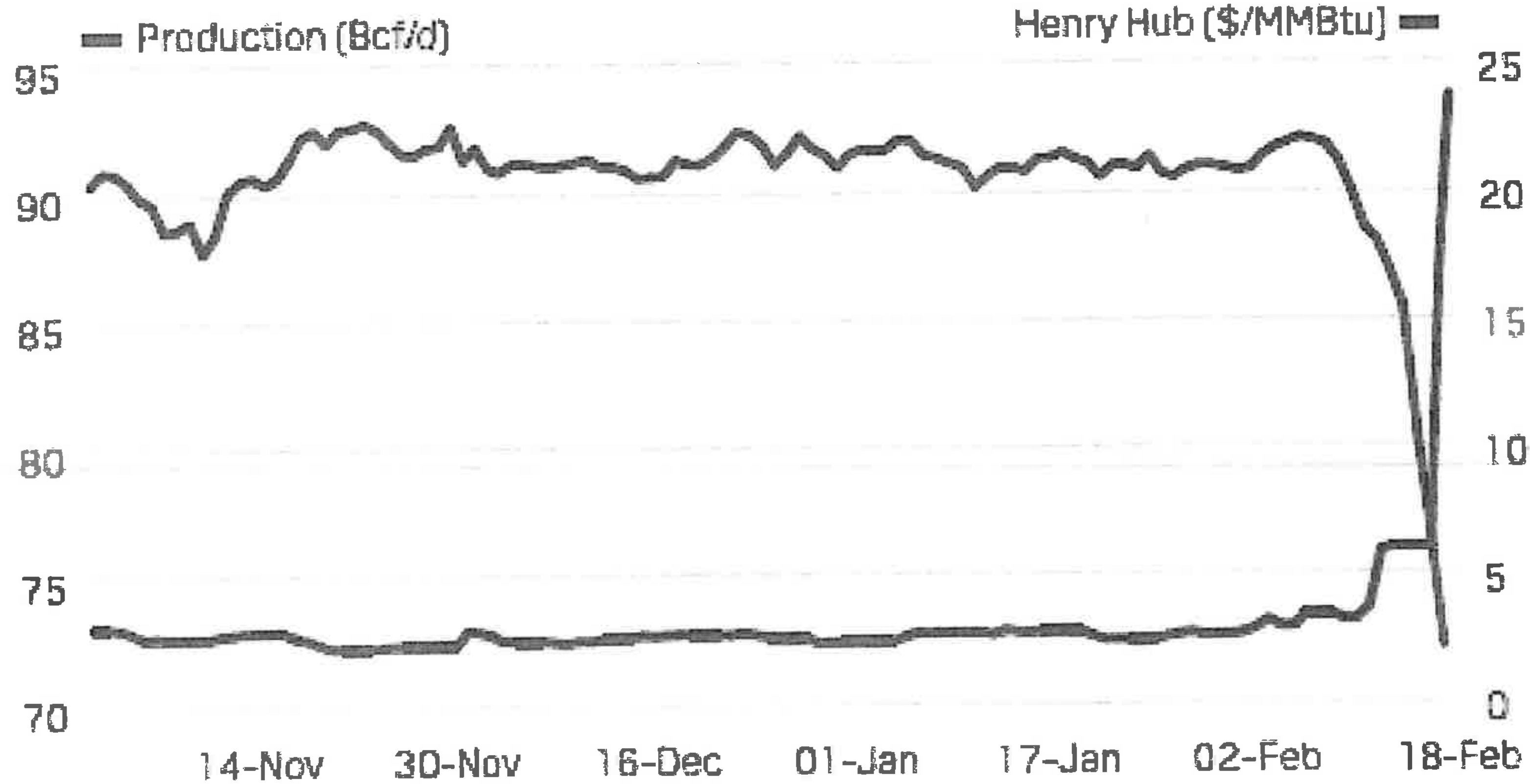
- Approximately 20% of Natural Gas Supply was offline, heavily concentrated in SPP footprint
- In 2018 'Bomb Cyclone' on 5-7% of production was lost

US DEMAND SETS RECORD HIGH AS SUPPLY SLUMPS



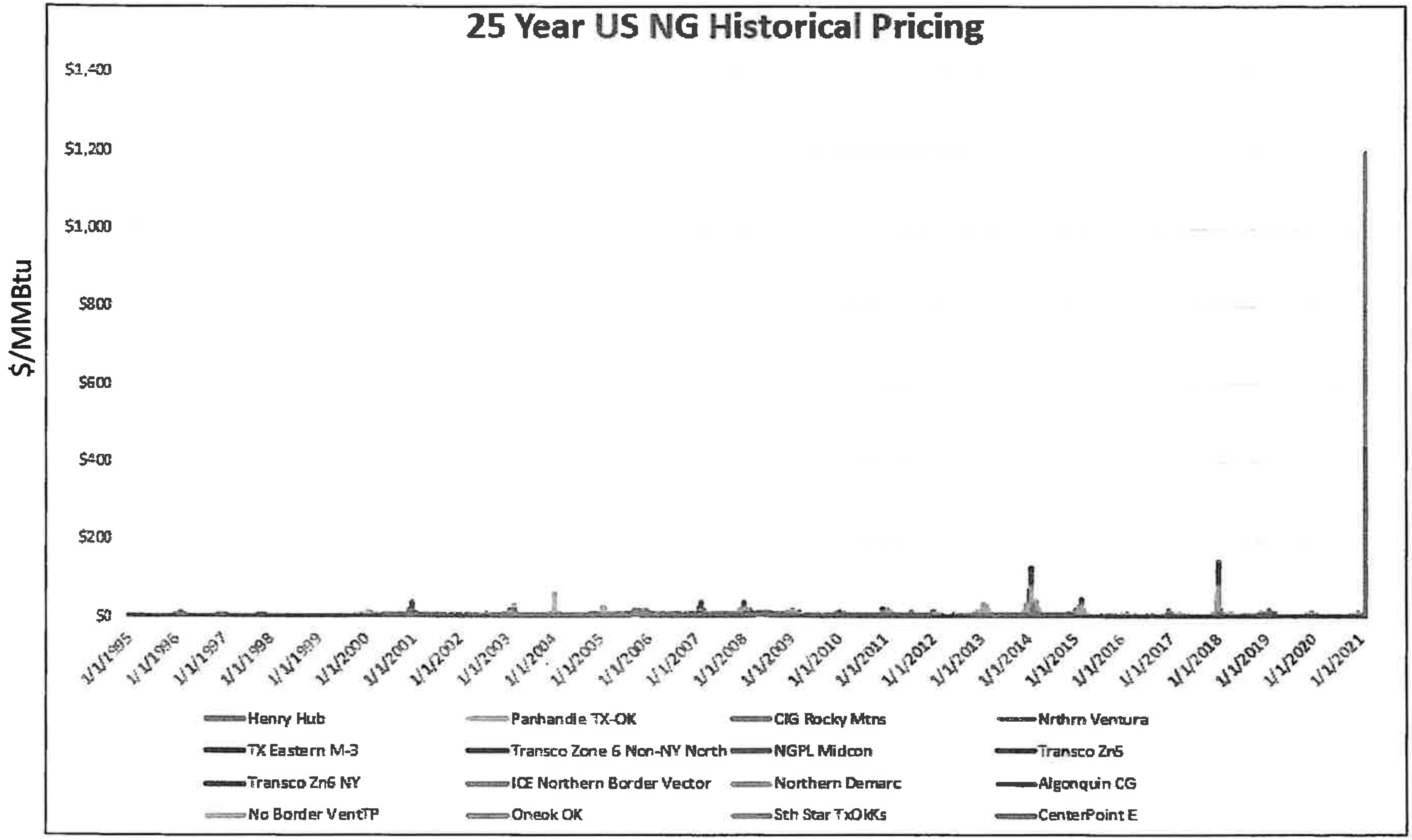
Source: S&P Global Platts Analytics, US Energy Information Administration

HENRY HUB CASH PRICES HIT RECORD HIGH AS US NATURAL GAS SUPPLY CONTINUES TO FALL



Source: S&P Global Platts

Daily Natural Gas Prices



payments are appropriate. Then it's written in the responses to the committee before this hearing, it was reported that $400 million went to those nongenerators. From that, my take, and committee members can look behind the SPP response. Those market participants, if you flip through about the fourth page from the back, you'll identify those are majority, if not all of those recipients from outside of the state of Nebraska. And I believe if I'm not correct, correct, my question to you is, are these nongenerators, do you know, are they investment companies?

LANNY NICKEL: I would venture to say that they are. Generally speaking, that's, that's what we would see participate.

BOSTELMAN: I would agree. I would agree. Thank you. And considering that the event reportedly, what I have found, what I have found in my, in our research we've done, it cost, this event cost Nebraskans about a billion dollars. This billion dollars comes from the pockets of Nebraska ratepayers. How is it appropriate or fair for generators and/or nongenerator generators to financially benefit either $400 million or others and not our ratepayers?

LANNY NICKEL: You know, that's a, it's a great question, and I have to take you at your word. I don't know what, what it cost Nebraska. I'll take you at your word. You know, there are certain provisions in our tariff that we are simply required to incorporate, the Federal Energy Regulatory Commission, and that's one of them. That's one of the aspects that FERC imposed on SPP, and it's the same provision in all of the markets that I'm aware of that. And there's a reason for, they believe that that provides more liquidity, fungibility in the marketplace by having these financial-only utilities. But I can tell you as a membership, our members debated that and some wanted to, you know, even fight it. And we did. FERC still said, you've got to do it. So we did. And that's--

BOSTELMAN: Sure.

LANNY NICKEL: That's the outcome of that.

BOSTELMAN: Sure. And specifically, I do have some information from Senator Wayne's hearing that he had on natural gas before, earlier this year. Six hundred and about twenty-five million dollars, I see through the gas industry that I can obtain-- attribute that to. That was preliminary thoughts. Specific towns in Nebraska: South Sioux City, $2.8 million; Wayne, $3 million; Falls City, Scribner, $5 million; Wakefield, $1.7. So as we start to look at the cost of this, that doesn't include like what Senator Brewer said, he got a call from one of the ranchers and they lost all their lambs in the barn. No electricity. We have companies in Senator Wayne's district that couldn't operate, couldn't function. We have a loss of generation, so I don't think that billion dollars is so far off. And so we're very concerned about what happened and how that affects our state. Regarding generation matching with load and instantaneous levels during events, in February 2021, did intermittency from renewable resources make load generation matching more difficult?

LANNY NICKEL: No, I don't think it did. Again, our forecast for wind, we're tracking really close to what was actually being produced, so it didn't cause us any balancing issues. What really hurt us the most in terms of that, having to take quick action. Because the fact is is that when we're balancing supply against demand, it's happening second by second by second. And if things change, and they change rapidly enough and in large enough scale, that's what creates problems for us. The wind wasn't picking up and dropping off dramatically. We did have a moment where some imported energy that we were getting from one of our neighbors was interrupted because of transmission loading on their system, and that happened over a period of about 15 minutes. And frankly, that's what led us to have to implement our, our load shedding there.

BOSTELMAN: One more question and then I'll let Senator Groene ask a question. So I do have several, so I'll try to, try to limit, someone else ask. Maintaining reliability with this large amount of renewables is extraordinary. Excuse me, let me ask the question first. Regarding generation matching, which I just said with load and instantaneous levels during the events of 2021, there was a comment made by your CEO, Barbara Sugg, and this is a quote. "Maintaining reliability with this large amount of wind is extraordinary," said Barbara Sugg, president and chief executive officer. "To manage this high volume of variable energy, we rely on accurate forecasting, our robust transmission system, a diverse generation mix and our equitable and efficient wholesale energy market." You mentioned resiliency before, and as you add on more generation and more unreliable generation your resiliency goes down, it causes more problem on the grid. How are you going to address that in the future?

LANNY NICKEL: Well, we hope to address it, and I know hope is not a plan. I heard that loud and clear. We plan to address that with one of the recommendations that has been sent to this task force, and that

APPENDIX NO. 20

Nebraska Power Association Load Capability Report

August 2021

20

NEBRASKA POWER ASSOCIATION

2021 NEBRASKA POWER ASSOCIATION
LOAD AND CAPABILITY REPORT

August 2021

2021 Nebraska Power Association Load and Capability Report

Executive Summary

In summary, based on Existing and Committed resources, the statewide deficit occurs in 2039 for the Minimum Obligation as shown in Exhibit 1. The statewide deficit for the Minimum Obligation in the 2020 report showed a State deficit occurring in 2026. Exhibit 2 is the corresponding load and capability data in tabular format. The deficit year changes due to "planned" generating units now being "committed".

The Minimum Obligation, with Planned and Studied resources included, is satisfied in all years as shown in Exhibit 3. The 2040 surplus of 319 MW in this study is actually 276 MW lower than what was shown in the 2020 study; a 2039 end year amount of 595 MW. This is mostly due to increased load growth.

Introduction

This report is the Nebraska Power Association (NPA) annual load and capability report, as per Item 3 in the statute below. It provides the sum of Nebraska's utilities' peak demand forecasts and resources over a 20-year period (2021-2040).

State Statute (70-1025) Requirement

70-1025. Power supply plan; contents; filing; annual report.(1) The representative organization shall file with the board a coordinated long-range power supply plan containing the following information:(a) The identification of all electric generation plants operating or authorized for construction within the state that have a rated capacity of at least twenty-five thousand kilowatts;(b) The identification of all transmission lines located or authorized for construction within the state that have a rated capacity of at least two hundred thirty kilovolts; and(c) The identification of all additional planned electric generation and transmission requirements needed to serve estimated power supply demands within the state for a period of twenty years.(2) Beginning in 1986, the representative organization shall file with the board the coordinated long-range power supply plan specified in subsection (1) of this section, and the board shall determine the date on which such report is to be filed, except that such report shall not be required to be filed more often than biennially.(3) An annual load and capability report shall be filed with the board by the representative organization. The report shall include statewide utility load forecasts and the resources available to satisfy the loads over a twenty-year period. The annual load and capability report shall be filed on dates specified by the board. Source Laws 1981, LB 302, § 3; Laws 1986, LB 948, § 1.

Demand and Capacity Expectations

Peak Demand Forecast

The current combined statewide forecast of non-coincident peak demand is derived by summing the demand forecasts for each individual utility. Each utility supplied a peak demand forecast and a load and capability table based on the loads having a 50/50 probability of being higher or lower. Over the twenty-year period of 2021 through 2040, the average annual compounded peak demand growth rate for the State is projected at 0.7% per year (individual utilities range from -0.1%/yr to 1.2%/yr). The escalation rate that was shown in last year's report for 2020 through 2039 was 0.6%.

Planning Reserve Margin Requirement/Reserve Sharing Pool

In addition to the load requirements of the state's customers, the state utilities must also maintain reserves above their peak demand forecast ("Minimum Obligation"). The "Minimum Obligation" line is the statewide obligation based on the 50/50 forecast (normal weather) and the minimum 12% reserve margin of the Southwest Power Pool (SPP) Reserve Sharing Pool. All SPP Reserve Sharing members must maintain the specified reserve requirement in order to assist each other in the case of emergencies such as unit outages. The reserve requirement of the pool is reduced by having a reserve sharing pool, instead of individual utilities carrying the entirety of their own reserves to protect them from the loss of their largest unit on their system. The 2021 NPA L&C Report utilizes the SPP planning reserve margin of 12% for the 20-year period.

The capacity required to meet the SPP planning reserve margin is a significant resource capability over and above the Nebraska load requirement. This amount of capacity equates to 736 MW in 2021 and 849 MW by 2040.

Resources

Existing/Committed

The State has an "Existing" in-service summer accreditable generating resource capability of 7,673 MW. This is up from 7,607 MW shown in the previous 2020 report. The changes were mostly increases in wind accreditation. There are 731 MW of "Committed" nameplate or 664 MW accredited resources included in this report (the projects have Nebraska Power Review Board approval if required – PURPA qualifying and non-utility renewable projects do not need NPRB approval). In 2023 OPPD's 150 MW Standing Bear Lake natural gas fired reciprocating engine project, 450 MW Turtle Creek natural gas combustion turbine project and the 81 MW (64.8 MW accredited) Platteview solar project are expected to be commercial. Also, in 2024 Grand Island's 50 MW Prairie Hills Wind Farm is to be completed. There is an additional 17.5 MW of committed renewable behind the meter generation (BTM) to be added between 2022 and 2023. This includes the "Committed" 1.0 MW Norfolk Battery Energy Storage System scheduled to be on-line in 2022.

Planned
"Planned" resources are units that utilities have authorized expenditures for engineering analysis, an architect/engineer, or permitting, but do not have NPRB approval - if that approval is required, or do not have a contractual commitment. OPPD has 419 MW of nameplate or 335 MW accredited renewable (solar) resources planned.

Studied
Resources identified as "Studied" for this report provide a perspective of future resource requirements beyond existing, committed and planned resources. For any future years when existing, committed, and planned resources would not meet a utility's Minimum Obligation, each utility establishes studied resources in a quantity to meet this deficit gap. These Studied resources are identified based on renewable, base load, intermediate, peaking, and unspecified resources considering current and future needs. The result is a listing of the preferable mix of renewable, base load, intermediate, peaking and unspecified resources for each year. The summation of studied resources will provide the basis for the NPRB and the state's utilities to understand the forecasted future need by year and by resource type. This can be used as a joint planning document and a tool for coordinated, long-range power supply planning.

There are 75 MW of "Studied" resources that include 0 MW of nameplate renewable resources, 25 MW of base load capacity in 2027, 0 MW of intermediate capacity, 0 MW of peaking resources and 50 MW of unspecified capacity in 2024.

Committed/Planned/Studied Exhibits
Exhibit 3 shows the statewide load and capability chart considering 7,673 MW of Existing, 731 MW of Committed (nameplate) (664 MW accredited), 419 MW Planned (nameplate or 335 MW accredited), and 75 MW of Studied resources. Some existing wind renewables are currently shown at "zero" accredited capability due to the small accreditation values allowable under SPP's Criteria (explained in next section). Exhibit 4 is the corresponding load and capability table. As intended, these exhibits show how the Minimum Obligation can be met with the addition of the studied resources.

The Committed, Planned, and Studied nameplate capability resources are summarized in Exhibit 5, (which includes BTM). Exhibit 6 summarizes the Existing, Committed, Planned, and Studied renewable resources and also includes BTM resources in the tabulation.

Non-Utility Resources

Non-utility wind purchases have also accelerated and are summarized as follows. This information is gathered from publicly available industry publications and newspapers and may not be complete. These projects also do not represent retail choice, as they are not directly attributed to serving retail customers within the state. The 318 MW (nameplate rated) Rattlesnake Creek wind facility began commercial operation in December 2018 and energy from this facility is purchased by Facebook and Adobe Systems. Facebook is procuring energy from Rattlesnake Creek for their data facility in Sarpy County. The WEC Energy Group (an electric generation and distribution and natural gas delivery holding company), based in Milwaukee, Wisconsin, signed a Purchase and Sale Agreement for 80% of the Upstream Wind Energy Center (202.5 MW nameplate) located just north of the City of Neligh. Invenergy, the developer, has retained a 20% interest in the project which went commercial in the first part of 2019. Both the J.M. Smucker Company and Vail Resorts have Power Purchase Agreements in place to purchase energy from the 230 MW (nameplate) Plum Creek Wind Project in Wayne County which went commercial in July 2020. Smucker's purchase is for 60 MW while Vail Resorts will purchase 310,000 MWh annually for 12 years. A Milligan 1 300 MW wind farm built in Saline County, by EDF Renewables did go commercial in May 2021. The announcement said it would sell its generated energy into the Southwest Power Pool. Hormel Foods has announced a Power Purchase Agreement for wind energy from a new wind farm near Milligan (Milligan 3), located in Saline County 60 miles southwest of Lincoln which had a projected completion date of 2020 but is not yet commercial. The wind farm had a planned capability of 74 MW (nameplate) of power. The 300 MW Thunderhead Energy Center that was announced to be built in Antelope and Wheeler counties with a completion date of the end of 2020 also is not commercial. This wind facility was to be built by Invenergy with AT&T reportedly taking all of the energy from it. NextEra's Little Blue Wind Project located in Webster and Franklin Counties is currently under construction. This up to 250 MW project is scheduled to begin operations by the end of 2021. No information on off-takers is available.

Non-Carbon, Renewable and Demand Side Resources

The State has 2,198 MW of commercially operating renewable nameplate resources for the peak of 2021, of which 77 MW are behind the utility meter (not net metered) as shown in Exhibit 6. There is also 114 MW of instate hydro for Nebraska's use not included in this total. These amounts do not include any wind which may be installed by developers in Nebraska for export to load outside the state. Wind with its intermittency is relied upon by Nebraska utilities for only a small percentage of its full nameplate rating to meet peak load conditions. Correspondingly, for wind and solar the SPP has criteria to determine this specific accreditable capacity percentage. The criteria are based on actual performance of solar and wind facilities and how successfully they produce energy during actual utility peak load hours. The rating is determined by following SPP's criteria to calculate the accredited rating for the facility. The accredited rating based on actual performance generally requires a minimum of 3 years' history. SPP criteria allows for a 5% accreditation rating for new wind installations with less than 3 years history and 10% for solar. SPP's Supply Adequacy Working Group is currently pursuing implementation of an effective load carrying capability (ELCC) method of determining wind, solar and storage accreditation which would replace the currently used criteria. The method is scheduled to go into effect for the summer of 2023. The ELCC is a probabilistic based accreditation reflecting an intermittent resource's ability to reliably serve load. The existing accreditation method produces a resulting accreditation which is independent of overall penetration of that type of resource in the SPP footprint. Contrarily, the ELCC is affected by overall penetration level of the resource in a footprint, and the general principle is that as overall penetration grows, the accreditation benefit on a percent of nameplate goes down. During the years before 2023, SPP will provide "information only" ELCC accreditation levels on an annual basis to provide SPP members/stakeholders with an indication of the magnitude of percentage accreditation in anticipation of actual implementation for the summer of 2023. Even as accredited capacity ratings decline, wind and solar generation renewable resources are desirable for being emission-free and having a zero fuel cost. Nebraska utilities are adding renewables to take advantage of these attributes.

In order to preserve an additional amount of certainty in the accreditation benefit which Load Responsible Entities (LRE) expect to receive from wind and solar resources, the SPP ELCC methodology allows for a priority tier under the ELCC study. The tier is based on the nameplate of the wind or solar portfolio as a percent of a LRE's recent historical peak load. The tier is 35% for wind and 20% for solar resources that have firm transmission service. This means as LREs across SPP continue to add wind and solar, they know their renewable accreditation for resources within these percentages will be diminished only up to a point. As an individual LRE may choose to add renewables beyond 35 and 20 percent, then those renewables will be included in a larger ELCC renewable tier and be subject to further diminishing ELCC accreditation on renewables. The SAWG is also implementing ELCC accreditation for storage resources which also receive diminished accreditation as the penetration of storage increases.

Demand side resources are loads that can be reduced, shifted, turned-off or taken off the grid with the goal of lowering the overall load utilities have to serve. Ideally this load is best reduced to correspond to utilities' peak load hours. The advantage for utilities is the demand reduction will reduce the need for adding accredited generation in current or future years.

Exhibit 6.1 shows the Statewide Renewable Generation by Nameplate. Exhibit 7.1 shows the Statewide Renewable and Greenhouse Gas Mitigating Resources.

Included below are summaries of the utilities in regard to their renewable and/or sustainable goals and demand side programs.

<u>NPPD</u>
NPPD owns or has agreements with these non-carbon resources:

- 558 MW of hydroelectric generation, including the Western Area Power Administration agreement.
- 770 MW of nuclear power at Cooper Nuclear Station.
- 320 MW of nameplate wind (NPPD's share).

For 2020, non-carbon generation resources were approximately 62% of NPPD's Native Load Energy Sales from the resources discussed above. Most of the non-carbon generation is due to nuclear, and 2020 was a refueling year.

In early 2021, NPPD signed a Letter of Intent to assist Monolith Materials in their sustainability pursuits by bringing additional renewable energy resources into the District's generation mix. A Request for Proposal (RFP) was issued this spring to solicit bids for new wind and/or solar facilities, as well as potential complementary energy storage, in accordance with this plan. Responses to the RFP are due this June. The expected completion date of the new generation is sometime in 2025. Due to the PPA timing and uncertainty of the renewables mix, this is not reflected in NPPD's load and capability at this time.

NPPD's Demand Side Management program consists of Demand Response and Energy Efficiency. NPPD presently has a successful demand response program, called the Demand Waiver Program, to reduce summer billable peaks. The majority of savings in this program are due to irrigation load control by various wholesale customers, which accounted for approximately 525 MW of demand reduction from NPPD's billable peak during the summer of 2020. Another 11 MW of demand reduction was realized from other sources.

NPPD implemented an interruptible rate, Special Power Product #8, allowing qualified large end-use customers (served by wholesale or retail) to curtail demand during NPPD specified periods.

NPPD has a series of energy efficiency and demand-side management initiatives under the EnergyWise^{SM} name. Annually, these programs have sought to achieve a first year savings of more than 12,000 MWh and demand reductions greater than 2 MW. Accumulated first year energy savings through 2020 are 353,150 MWh and demand reductions are 57 MW.

NPPD recently completed a Carbon Business Risk Reduction study to explore resource mixes that are low cost and still provide reliability under a variety of potential future carbon regulations. The study results will be one consideration among many when NPPD's Board of Directors establishes a strategic directive (SD-05) concerning decarbonization. The process to develop this strategic directive has started and is expected to be used in development of the next Integrated Resource Plan (IRP) which is due in early 2023. At this time NPPD has no plans to retire/decommission any of its existing generation units.

OPPD

OPPD values a diverse resource mix as a means of achieving its mission of providing affordable, reliable, and environmentally sensitive energy services to its customers. In November of 2019 OPPD's Board of Directors adopted a goal in its Strategic Directives of achieving net zero carbon production by 2050. In alignment with this goal, and balanced with its mission, OPPD in 2021 is studying Pathways to Decarbonization. This will model the current portfolio of generation resources, in addition to resources and technology needed to meet the goal of decarbonization, while supporting future load growth and OPPD's mission. OPPD will incorporate the information resulting from the Power with Purpose study and the Pathways to Decarbonization study into its 2021 Integrated Resource Plan.

At the close of 2020, OPPD met 38.4% of retail customer electrical energy sales with wind energy, energy from landfill gas, hydro energy, and solar energy. OPPD's renewable portfolio at 2020 year-end consisted of 971.7 MW of wind by nameplate, 5 MW of nameplate solar, 6.3 MW of landfill gas generation as well as purchased hydro power.

OPPD has announced a new 81 MW (nameplate) utility scale solar facility in Saunders County south of Yutan. The Platteview Solar will be a 500 acre facility and is targeted for construction beginning in 2022. This is the first step towards OPPD's Power with Purpose intended goal of 400 to 600 MW of utility scale solar power.

OPPD has received Power Review Board approval and is in the process of sourcing its first utility-scale battery storage facility. This resource will be utilized as a generation and transmission asset providing energy arbitrage, voltage support and various other functions, with a power rating of 1 MW and a storage capacity of 2 MWh. The project will be partially funded through the BRIGHT grant from the Nebraska Environmental Trust and is planned to be operational in late 2022.

OPPD's demand side resource programs can achieve over 117 MW of peak load reduction ability as of the summer of 2021. Existing programs consist of a customer air conditioner management program, thermostat control, lighting incentive programs, and various innovative energy efficiency projects. Additionally, OPPD can reduce its demand with assistance from a number of large customers who utilize OPPD's curtailable rate options. During summer peak days, any demand reductions from these customers are coordinated with OPPD in advance of the peak afternoon hours.

Demand side resource programs have enjoyed the support of OPPD stakeholders. OPPD will continue to grow its demand side programs in the next 10 years. Benefits of this increase in demand side programs include helping OPPD to maintain its SPP reserve requirements. To grow its demand side resource portfolio, OPPD will increase existing programs and promote additional program types. An expansion to the Smart Thermostat Program was launched in May of 2021 which includes the addition of 3 more thermostat choices for residential customers. OPPD will build its demand side resource portfolio in manners which are cost effective and take into account customer expectations.

OPPD makes available a net-metering rate to all consumers that have a qualified generator. The qualified generator must be interconnected behind the consumer's service meter located on their premises and may consist of one or more sources as long as the aggregate nameplate capacity of all generators is 25 kW or less. The qualified generator must use as its energy source methane, wind, solar, biomass, hydropower or geothermal. OPPD's Board of Directors is currently reviewing modification to this policy to increase the allowable limit to 100kW or less, with a decision expected in the August 2021 timeframe.

<u>MEAN</u>

In January 2020, the MEAN Board of Directors approved a resolution establishing MEAN's 2050 Vision, with a goal of achieving a carbon neutral resource portfolio by the year 2050. MEAN's 2022 Integrated Resource Plan will form the initial direction for future actions and resource decisions to realize the 2050 Vision. Following the IRP's direction, MEAN staff will work in collaboration with Participants to construct policies around resource planning, portfolio optimization, and emissions reduction to achieve the 2050 carbon neutral goal.

The results of MEAN's previous IRP analysis and modeling favored a plan that would meet future MEAN capacity and energy needs by incorporating additional renewable resources into the portfolio. Renewable resource portfolios offered comparatively low costs in several scenarios as well as the potential to create local benefits for MEAN communities.

In serving the needs of its total membership, MEAN's system-wide resource portfolio includes 50% non-carbon resources on the basis of nameplate capacity, consisting of 32% WAPA hydro allocations, 14% renewables (wind, small hydro, and landfill gas), and 4% nuclear.

As a member driven and member owned utility, MEAN procures renewable energy assets at the direction of its owners. Currently, MEAN maintains a wind pool, which allows member communities to subscribe for purchase of a requested amount of wind energy on an annual basis. This allows each community to tailor its resource portfolio to meet its specific demands and obligations as individual municipal utilities have renewable goals that can range from 0% to 100% of energy requirements. MEAN annually surveys its owners to determine individual goals for renewable energy requirements. When there are significant changes in demand for renewable energy, the MEAN Board considers the approval of new renewable purchases. MEAN's wind pool is currently fully subscribed, and the Board is considering the need for additional wind energy.

In 2018, MEAN finalized the latest addition to its renewable energy portfolio. While MEAN's 10.5 MW wind project near Kimball, NE was decommissioned in 2017, a new 30 MW wind farm was constructed at the same Kimball site. MEAN has entered into a PPA to purchase the entirety of the energy generation of the wind farm.

MEAN is currently exploring community solar installations to satisfy community demands for localized green non-carbon initiatives. Based on the results of a survey soliciting the level of interest in locally-owned solar facilities, MEAN staff contacted Participants to further discussions and determined 12 communities ready to proceed toward solar procurement. MEAN is currently authoring a joint RFP for more advantageous pricing, which is projected for release in early summer of 2021. Bid awards are planned for late summer, and the start of construction planned for fall. An earlier attempt to facilitate a joint community solar project was abandoned when, due to the resulting bid prices and economic climate in Participant communities, no interested parties decided to move forward with the purchase. Projections from solar developers indicate that pricing for this new RFP will be more favorable, increasing the likelihood of multiple installations. MEAN remains responsive to opportunities for utility-scale or community-scale solar projects in the best interest of the membership.

MEAN previously established a committee to focus on the integration of renewable resources within member communities. The increasing presence of renewable distributed generation offers unique opportunities that can benefit both MEAN and local residents. In 2017 and again in 2019, MEAN revised its Renewable Distributed Generation policy to increase the size of allowable community owned and locally-sited renewable energy resources. Should Participant communities desire a larger allowance for community-owned renewables, the Board can take up the issue for an increase in this limitation.

MEAN has utilized a variety of demand side management tools to help reduce load and energy requirements. MEAN presently administers an ENERGYsmart commercial LED lighting program, which includes cash incentives paid directly to commercial customers to help cover the cost of lighting upgrades and replacements. This program is available to commercial businesses of MEAN long-term power participants. In 2019, MEAN initiated additional energy efficiency incentives offered to residential end-use customers of its Participants. These new programs include rebates for programmable thermostats, residential insulation, and HVAC tune-ups. In May of 2021, the Board again approved an expansion of this program to include a residential heat pump program. MEAN staff continues to evaluate the benefits of additional energy efficiency and demand side management options to decrease demand-related costs for MEAN and its participants.

<u>LES</u>

After participating in a yearlong educational series on establishing a new carbon reduction goal and soliciting public opinion, the LES Administrative Board in November 2020 adopted what LES believes to be one of the more aggressive decarbonization goals in the United States. This new goal will aim to achieve net-zero carbon dioxide production from LES' generation portfolio by 2040.

In the near term, LES plans to pursue the goal with the same approach it's used over the last decade; watching for opportunities to improve its generation portfolio while also reducing carbon emissions. This approach has yielded solid results to date, as from 2010 – 2020 LES has reduced its carbon dioxide emissions by 53% and the carbon intensity of the energy produced by 45%. On a nameplate basis, approximately one-third of LES' resources are currently fueled by coal, one-third fueled from natural gas, and one-third are renewables (primarily wind and hydro). In 2020, energy production from renewable sources was equivalent to 49% of LES' retail sales.

LES' Sustainable Energy Program (SEP) offers customers and contractors incentives for energy-efficient installations and upgrades at their home or business. First adopted in 2009, the SEP now offsets the energy use of about 13,000 average Lincoln homes.

Under the Peak Rewards program, LES leverages residential customers' own smart thermostats to pre-cool spaces prior to the initiation of an LES-controlled demand response event, allowing for a reduction in summer peak demand while still maintaining residential comfort. LES introduced a new demand response pilot program under the umbrella of Peak Rewards in 2021, incentivizing plug-in electric vehicle owners to also avoid charging during peak load periods.

LES has two programs that support customers wishing to pursue their own renewable generation. Under LES' net-metering rate rider, customers can install a 25-kW or smaller renewable generator to serve their homes or small businesses. LES also has a renewable generation rate for customers interested in generating and selling all output to the utility rather than serving a home or small business. Systems greater than 25 kW up to 100 kW will qualify for this rate. Customers under each rate receive a one-time capacity payment based on the value of the avoided generating capacity on system peak.

The energy payment amount for new installations is based on LES' existing retail rates and is scheduled to be reduced as predetermined, total service area renewable-installation thresholds are met over time. In early 2017, LES reached this first milestone, with applications exceeding 1 MW.

In August 2014, LES launched the SunShares program, allowing customers to voluntarily support a local community solar project through their monthly bill. This program led to LES contracting for a local, approximately 5-MW_{DC}/4-MW_{AC} solar facility, which began commercial operation in June 2016. The facility represents the first utility-scale solar project in Nebraska and is still one of the largest projects in the region.

The community solar project also supports LES' virtual net metering program. As part of this program, customers receive a credit on their monthly bill based on their level of enrollment and the actual output of the facility. Enrollment began in December 2016, with the first credits appearing on bills in January 2017. The enrollment fee was originally a one-time, upfront payment, but in 2019 LES also added the option for customers to pay the associated fee over 36 months via their normal LES bill. The program will run for nearly 20 years, coinciding with the life of the solar project contract.

Hastings Utilities

Hastings Utilities has no formal renewable energy goals but will monitor the economics and interest of renewable energy. Hastings Utilities will work with customers who are interested in pursuing renewable energy to find mutual benefit for a successful project. Hastings Utilities worked with its customer, Central Community College, to implement a 1.7 MW wind turbine on the Hastings CCC campus.

Hastings Utilities has completed the construction of a 1.5 MW Community Solar Project to respond to customer requests for renewable energy. Customers can participate by purchase of solar panels or solar shares. The project was completed in September of 2019.

Hastings Utilities is conducting an Integrated Resource Plan (IRP) study of current and future resources of generation.

City of Grand Island Utilities

Grand Island does not have any formal renewable/sustainable goals. The Grand Island City Council has directed the Utilities Department to explore opportunities as they develop. In 2017, Grand Island Utilities signed a Power Purchase Agreement with Sempra for 50 MW of Prairie Hills Wind Farm in Custer County, NE. This wind farm is currently awaiting the completion of the SPP interconnection study. It is expected to be online within a couple of years.

Grand Island Utilities approved its first small scale residential solar installation in 2015. Changes were made to City Code to accommodate demand side resources with an expectation that more resources will follow. Since then, several smaller scale residential solar generators have been installed. Additional changes to City Code have been made to allow larger renewable generation facilities between 25 KW and 100 KW. One facility in this category is anticipated by the end of 2020.

In 2017, Grand Island Utilities signed a Power Purchase Agreement for a 1 MW behind the meter solar installation with Sol Systems. This facility went into service in 2018.

City of Fremont Utilities

Fremont currently operates two solar arrays, which offers residents two options on the project. Electric customers can either purchase their own solar panels or purchase solar shares from the Community Solar Farm. Solar array #1 is 1.32 MW and solar array #2 is 0.99 MW. Fremont also has a Purchase Power Agreement with NextEra for 40.89 MW of wind energy from the Cottonwood Wind Farm in Webster County, NE.

SPP Generator Interconnection Queue

The SPP Generator Interconnection Queue process provides a means for planners and developers to submit new generation interconnection projects into the Queue for validation, study, analysis and, ultimately, execution of a Generator Interconnection Agreement.

A listing of the projects in the Queue from June of this year for Nebraska shows around 1,745 nameplate megawatts for battery storage, 6,330 MW of solar, 7,731 MW of wind and 310 MW that is considered hybrid. For reference, there is at this time approximately 2,700 MW of nameplate wind installed in the State. Also listed are conventional combustion turbine and diesel generation amounting to 3,571 MW. Based on past history many or most of these proposed projects listed in the SPP Queue will not get built.

Distributed Generation

Distributed generation is providing wholesale and retail power suppliers numerous new opportunities to interface with customers. Power purchase agreements with smaller wind developers are available to retail power suppliers in the magnitude of 1.5 to 10 MW. This is occurring due to agreements between the wholesale power suppliers and the retail power suppliers. These agreements allow for a portion of the retail power supplier's energy requirements to come from private renewable energy developers that are located behind the wholesale power supplier's meter.

Next, with the decline in the cost of solar installations, the continuation of tax benefits and net metering rates, retail customers are installing small scale solar arrays. As these installations prove more cost effective and with the development of small energy storage more of these installations are being constructed. These installations are being installed in both rural and residential applications. Also, larger solar array installations that are not eligible for net metering rates are being considered and installed. Many of these arrays are community solar projects. Lincoln Electric System contracted with a developer to install a 5 MW $_{DC}$ (4 MW $_{AC}$) array where individuals can purchase shares. NPPD has retail communities with operating community solar facilities ranging in size from 100 kW to 5.7 MW. Other NPPD retail communities are interested in developing community solar array installations in sizes up to 8.5 MW $_{AC}$. OPPD has a community solar facility sized at 5 MW. OPPD's customers have already subscribed to the full production of this facility. Therefore, more private involvement with local utilities is providing additional opportunities to increase the utilization of renewable energy.

In addition, an NPPD retail community also has plans to tie a 1 MW / 2 MWh Battery Energy Storage System (BESS) to a community solar project. The BESS will be charged through generation provided by the solar unit and discharged daily to accomplish several goals, such as demand management, voltage support, and smoothing and shifting variable renewable energy generation. The BESS unit will store approximately the amount of electricity that a small home would use over the course of two months.

Exhibit 6 lists all of the Nebraska renewable resources, with two columns identifying whether the resource is "Behind the Meter – Utility" or "Behind the Meter – Non Utility". Behind the Meter – Utility resources are those who have a signed Power Purchase contract or are owned by the utility.

Resource Life Considerations

The Nuclear Regulatory Commission (NRC) determined in August 2014 that a new rule making was not required and confirmed that existing license renewals, where granted, provided a robust framework for second license renewals beyond the initial 20-year renewal term. In addition, no changes are needed to environmental regulations to allow for future license renewal activities.

Cooper Nuclear Station's (CNS) operating license is set to expire January 18, 2034. Although NPPD has not fully studied a second operating license renewal, for purposes of this report, it is assumed CNS will continue to operate through 2040.

NPPD's listed North Platte and Columbus hydro facilities operate under a Federal Energy Regulatory Commission license. The North Platte facility is presently operating under a 40-year license, with the license requiring renewal in 2038. The Columbus Hydro facility received a new 30-year operating license, with the license requiring renewal in 2047. Given the focus on carbon free generation resources NPPD and Loup are assuming these facilities will continue to be maintained and licensed and will remain an essential part of NPPD's generation mix for an extended period of time.

The wind farms included in this report are shown at the life listed in the various power purchase agreements (PPA), usually 20 or 25 years. Most agreements have an option for life extension. Utilities will decide whether to exercise those options when the PPAs near their end. In order for those utilities to maintain their renewable goals these utilities will have to either exercise those options or develop other renewable resources.

Nebraska's existing generator capability resources are listed by unit in Exhibit 7. Nebraska has 7,673 MW of existing resources. 1,144 MW or 15% of that total are greater than 50 years old today. Another 2,774 MW or 36% are 41 to 50 years old today. Most of these units have no planned retirement date. By 2040 approximately 3,918 MW will reach 60 years of age in this 20-year study. Each utility will make their own determination on the life of their generating plants taking into account many factors, including economics. At this time, there are no plans to retire these older units unless stated in the report.

Although Nebraska has sufficient generating resources when including studied resources beyond 2040 as shown in Exhibits 3 & 4, utilities may face increased environmental restrictions that could require the retirement of older fossil units. This could advance the statewide need date several years earlier.

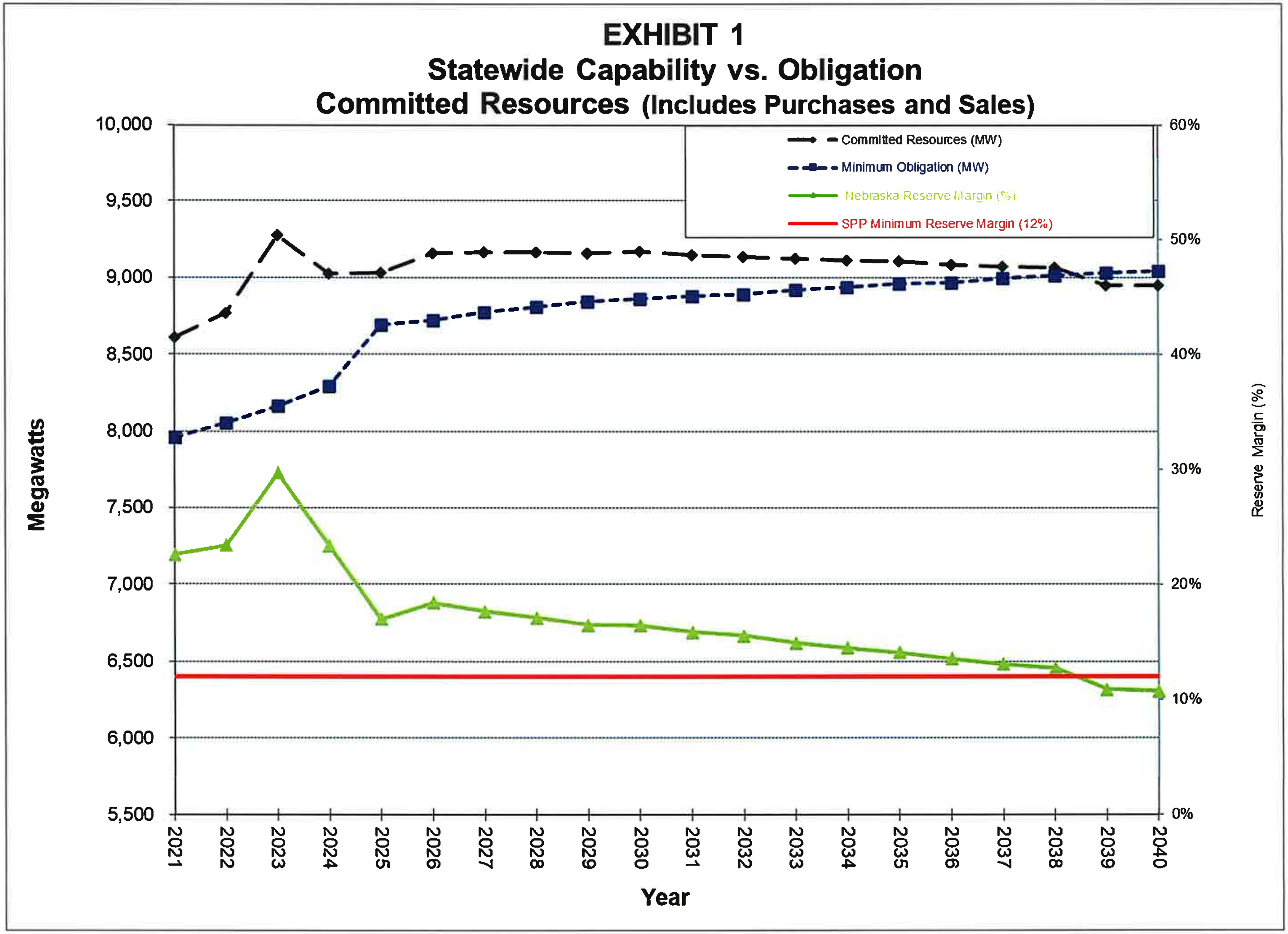


EXHIBIT 1
Statewide Capability vs. Obligation
Committed Resources (Includes Purchases and Sales)
Committed Resources (MW)
Minimum Obligation (MW)
Nebraska Reserve Margin (%)
SPP Minimum Reserve Margin (12%)
Megawatts
10,000
9,500
9,000
8,500
8,000
7,500
7,000
6,500
6,000
5,500
60%
50%
40%
30%
20%
10%
0%
Reserve Margin (%)
2021
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EXHIBIT 2
NEBRASKA STATEWIDE
Committed Load & Generating Capability in Megawatts
Summer Conditions (June 1 to September 30)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
1 Annual System Demand	7,224	7,311	7,406	7,523	7,877	7,904	7,951	7,985	8,016	8,030	8,047	8,056	8,083	8,101	8,118	8,127	8,151	8,166	8,183	8,193	0.7%
2 Firm Power Purchases - Total	1,171	1,163	1,153	1,155	1,156	1,157	1,159	1,160	1,162	1,163	1,165	1,166	1,168	1,169	1,171	1,172	1,174	1,175	1,176	1,178	
3 Firm Power Sales - Total	77	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	
4 Annual Net Peak Demand (1-2+3)	6,130	6,211	6,315	6,431	6,783	6,808	6,854	6,886	6,916	6,928	6,944	6,952	6,977	6,994	7,009	7,017	7,040	7,053	7,068	7,077	
5 Net Generating Capability (owned)	7,673	7,678	8,346	7,995	7,993	7,991	7,989	7,987	7,982	7,993	7,979	7,958	7,945	7,932	7,921	7,894	7,885	7,876	7,761	7,761	
6 Firm Capacity Purchases -Total	1,054	1,067	1,039	921	815	817	823	819	813	813	802	805	802	802	803	803	803	802	795	793	
7 Firm Capacity Sales -Total	1,212	1,081	1,198	984	872	745	745	741	737	736	736	728	727	726	726	726	726	726	719	719	
8 Adjusted Net Capability (5+6-7)	7,515	7,665	8,187	7,932	7,937	8,063	8,067	8,066	8,058	8,070	8,046	8,035	8,020	8,009	7,999	7,971	7,962	7,952	7,837	7,836	
9 Net Reserve Capacity Obligation (4 x 0.12)	736	745	758	772	814	817	823	826	830	831	833	834	837	839	841	842	845	846	848	849	
10 Total Firm Capacity Obligation (4+9)	6,865	6,956	7,073	7,202	7,597	7,625	7,677	7,713	7,746	7,760	7,778	7,786	7,814	7,833	7,850	7,859	7,884	7,899	7,916	7,927	
11 Surplus or Deficit (-) Capacity @ Minimum Obligation (8-10)	650	709	1,114	730	340	437	390	353	313	310	268	249	206	176	148	112	77	53	-79	-91	
12 Nebraska Reserve Margin ((8-4)/4)	22.6%	23.4%	29.6%	23.4%	17.0%	18.4%	17.7%	17.1%	16.5%	16.5%	15.9%	15.6%	15.0%	14.5%	14.1%	13.6%	13.1%	12.8%	10.9%	10.7%	
13 Nebraska Capacity Margin ((8-4)/8)	18.4%	19.0%	22.9%	18.9%	14.5%	15.6%	15.0%	14.6%	14.2%	14.1%	13.7%	13.5%	13.0%	12.7%	12.4%	12.0%	11.6%	11.3%	9.8%	9.7%	
Committed Resources (MW) (8+2-3)	8,609	8,766	9,279	9,025	9,031	9,158	9,164	9,165	9,158	9,172	9,149	9,139	9,126	9,116	9,107	9,081	9,074	9,065	8,952	8,952	
Minimum Obligation (MW) (1+9)	7,960	8,057	8,164	8,295	8,691	8,721	8,774	8,811	8,846	8,861	8,880	8,890	8,920	8,940	8,959	8,970	8,996	9,012	9,031	9,043	

EXHIBIT 3
Statewide Capability vs. Obligation
Committed, Planned & Studied Resources (Includes Purchases and Sales)

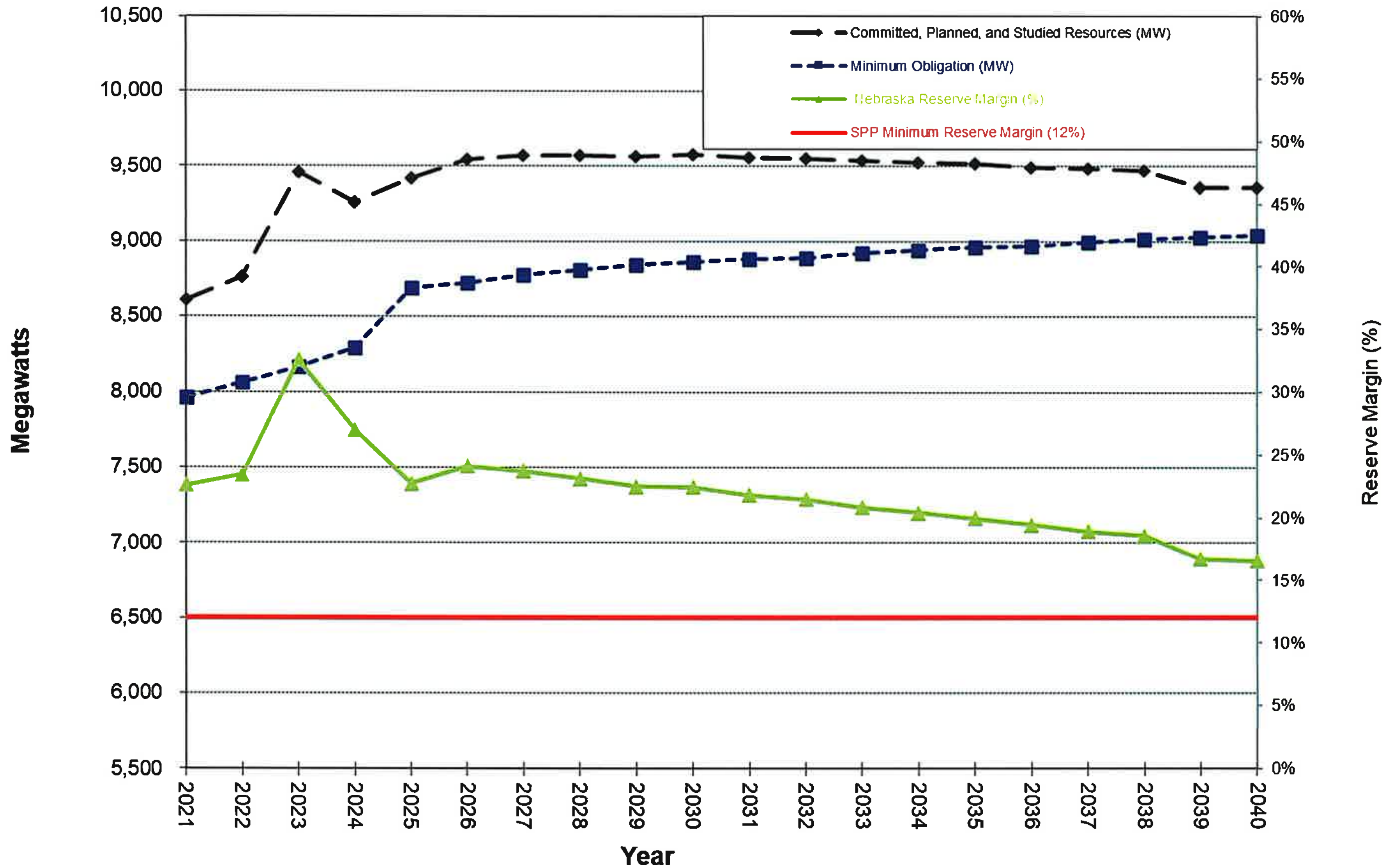


EXHIBIT 4
NEBRASKA STATEWIDE
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (June 1 to September 30)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Annual System Demand	7,224	7,311	7,406	7,523	7,877	7,904	7,951	7,985	8,016	8,030	8,047	8,056	8,083	8,101	8,118	8,127	8,151	8,166	8,183	8,193
2 Firm Power Purchases - Total	1,171	1,163	1,153	1,155	1,156	1,157	1,159	1,160	1,162	1,163	1,165	1,166	1,168	1,169	1,171	1,172	1,174	1,175	1,176	1,178
3 Firm Power Sales - Total	77	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
4 Annual Net Peak Demand (1-2+3)	6,130	6,211	6,315	6,431	6,783	6,808	6,854	6,886	6,916	6,928	6,944	6,952	6,977	6,994	7,009	7,017	7,040	7,053	7,068	7,077
5 Net Generating Cap-ability (owned)	7,673	7,678	8,529	8,227	8,378	8,376	8,399	8,398	8,392	8,403	8,390	8,368	8,355	8,342	8,332	8,304	8,295	8,286	8,171	8,171
6 Firm Capacity Purchases -Total	1,054	1,067	1,039	921	815	817	823	819	813	813	802	805	802	802	803	803	803	802	795	793
7 Firm Capacity Sales -Total	1,212	1,081	1,198	984	872	745	745	741	737	736	736	728	727	726	726	726	726	726	719	719
8 Adjusted Net Capability (5+6-7)	7,515	7,665	8,370	8,165	8,322	8,448	8,477	8,476	8,469	8,481	8,456	8,445	8,430	8,419	8,409	8,381	8,372	8,362	8,248	8,246
9 Net Reserve Capacity Obligation (4 x 0.12)	736	745	758	772	814	817	823	826	830	831	833	834	837	839	841	842	845	846	848	849
10 Total Firm Capacity Obligation (4+9)	6,865	6,956	7,073	7,202	7,597	7,625	7,677	7,713	7,746	7,760	7,778	7,786	7,814	7,833	7,850	7,859	7,884	7,899	7,916	7,927
11 Surplus or Deficit (-) Capacity @ Minimum Obligation (8-10)	650	709	1,297	963	725	823	800	764	723	721	678	659	616	586	558	522	488	463	331	319
12 Nebraska Reserve Margin ((8-4)/4)	22.6%	23.4%	32.5%	27.0%	22.7%	24.1%	23.7%	23.1%	22.5%	22.4%	21.8%	21.5%	20.8%	20.4%	20.0%	19.4%	18.9%	18.6%	16.7%	16.5%
13 Nebraska Capacity Margin ((8-4)/8)	18.4%	19.0%	24.5%	21.2%	18.5%	19.4%	19.1%	18.8%	18.3%	18.3%	17.9%	17.7%	17.2%	16.9%	16.6%	16.3%	15.9%	15.7%	14.3%	14.2%
Committed, Planned and Studied Resources (MW) (8+2-3)	8,609	8,766	9,461	9,258	9,416	9,543	9,574	9,575	9,568	9,582	9,559	9,549	9,536	9,526	9,517	9,491	9,484	9,476	9,362	9,362
Minimum Obligation (MW) (1+9)	7,960	8,057	8,164	8,295	8,691	8,721	8,774	8,811	8,846	8,861	8,880	8,890	8,920	8,940	8,959	8,970	8,996	9,012	9,031	9,043

EXHIBIT 5

Committed, Planned and Studied Resources, MW

Utility	Unit Name	New Existing	Committed	Planned	Studied	Duty Cycle	Unit Type	Fuel Type	Behind Meter	Capacity, Thermal Units	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Fremont	Future Base				S	B		NG		25.0	0	0	0	0	0	0	25	25	25	25
	Future Use										0	0	0	0	0	0	0	0	0	0
Fremont	Total									25.0	0	0	0	0	0	0	25	25	25	25
Grand Island	Prairie Hills Wind Farm		C			R	R	W		50.0	0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Grand Island	Total									50.0	0	0	0	50	50	50	50	50	50	50
Hastings	Hastings Community Solar	E				R	R	S	Y	1.5	2	2	2	2	2	2	2	2	2	2
	Future Use										0	0	0	0	0	0	0	0	0	0
Hastings	Total									1.5	2	2	2	2	2	2	2	2	2	2
LES	Future Peak					P				0.0	0	0	0	0	0	0	0	0	0	0
LES	Total									0.0	0	0	0	0	0	0	0	0	0	0
Towns and Districts	S. Sioux City NG Generation Plant	E				B		NG	Y	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
	Superior Solar	E				R		S	Y	0.0	0	0	0	0	0	0	0	0	0	0
	Future Use										0	0	0	0	0	0	0	0	0	0
Towns and Districts	Total									2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
MEAN	Future Intermediate					I				0.0	0	0	0	0	0	0	0	0	0	0
	Future Unspecified				S	U				50.0	0	0	0	50	50	50	50	50	50	50
	Future Base					B				0.0	0	0	0	0	0	0	0	0	0	0
MEAN	Total									50.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
NPPD	Custer PPD - Prairie Hills Wind		C			R	R	W	Y	8.0	0	0	8	8	8	8	8	8	8	8
	Norfolk Community Solar		C			R	R	S	Y	8.5	0.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
	Norfolk Battery Energy Storage System		C					S	Y	1.0	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Future Renewable					R	R			0.0	0.0	0	0	0	0	0	0	0	0	0
	Future Peak					P				0.0	0.0	0	0	0	0	0	0	0	0	0
	Future Intermediate					I				0.0	0.0	0	0	0	0	0	0	0	0	0
	Future Base					B				0.0	0.0	0	0	0	0	0	0	0	0	0
NPPD	Total									17.5	0	10	18	18	18	18	18	18	18	18
OPPD	Future Base					B				0.0	0	0	0	0	0	0	0	0	0	0
	Future Unspecified			P		U				0.0	0	0	0	0	0	0	0	0	0	0
	Standing Bear Lake		C			P	RE	NG		150.0	0	0	150	150	150	150	150	150	150	150
	Turtle Creek		C			P	CT	NG		450.0	0	0	450	450	450	450	450	450	450	450
	Future Intermediate					I				0.0	0	0	0	0	0	0	0	0	0	0
	Platteview		C			R	R	S		81.0	0	0	81	81	81	81	81	81	81	81
	Future Renewable			P		R	R	S		419.0	0	0	228	228	419	419	419	419	419	419
	Total									1100.0	0	0	909	909	1100	1100	1100	1100	1100	1100
OPPD	Nebraska Grand Total									1246	4	13	930	1030	1221	1221	1246	1246	1246	1246

Utility	Unit Name	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
Fremont	Future Base	25	25	25	25	25	25	25	25	25	25	
	Future Use	0	0	0	0	0	0	0	0	0	0	
Fremont	Total	25	25	25	25	25	25	25	25	25	25	
Grand Island	Prairie Hills Wind Farm	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	
Grand Island	Total	50	50	50	50	50	50	50	50	50	50	
Hastings	Hastings Community Solar	2	2	2	2	2	2	2	2	2	2	
	Future Use	0	0	0	0	0	0	0	0	0	0	
Hastings	Total	2	2	2	2	2	2	2	2	2	2	
LES	Future Peak	0	0	0	0	0	0	0	0	0	0	
LES	Total	0	0	0	0	0	0	0	0	0	0	
Towns and Districts	S. Sioux City NG Generation Plant	2.00	2.00	2.00	2.00	2.00	2.00	2.00	0.00	0.00	0.00	
	Superior Solar	0	0	0	0	0	0	0	0	0	0	
	Future Use	0	0	0	0	0	0	0	0	0	0	
Towns and Districts	Total	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.0	0.0	0.0	
MEAN	Future Intermediate	0	0	0	0	0	0	0	0	0	0	
	Future Unspecified	50	50	50	50	50	50	50	50	50	50	
	Future Base	0	0	0	0	0	0	0	0	0	0	
MEAN	Total	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	
NPPD	Custer PPD - Prairie Hills Wind	8	8	8	8	8	8	8	8	8	8	
	Norfolk Community Solar	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	
	Norfolk Battery Energy Storage System	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
	Future Renewable	0	0	0	0	0	0	0	0	0	0	
	Future Peak	0	0	0	0	0	0	0	0	0	0	
	Future Intermediate	0	0	0	0	0	0	0	0	0	0	
	Future Base	0	0	0	0	0	0	0	0	0	0	
NPPD	Total	18	18	18	18	18	18	18	18	18	18	
OPPD	Future Base	0	0	0	0	0	0	0	0	0	0	
	Future Unspecified	0	0	0	0	0	0	0	0	0	0	
	Standing Bear Lake	150	150	150	150	150	150	150	150	150	150	
	Turtle Creek	450	450	450	450	450	450	450	450	450	450	
	Future Intermediate	0	0	0	0	0	0	0	0	0	0	
	Platteview	81	81	81	81	81	81	81	81	81	81	
	Future Renewable	419	419	419	419	419	419	419	419	419	419	
	Total	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	
OPPD	Nebraska Grand Total	1246	1246	1246	1246	1246	1246	1246	1244	1244	1244	#

Unit Type	Fuel type		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
	HS-Run of River	No Behind Meter Resources Included																					
Unit Type	NG-Natural Gas	New Existing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
H-Hydro	O-Oil	Committed	0	0	681	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	
D-Diesel	Coal-Coal	Planned	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
N-Nuclear	HR-Reservoir	Planned Renewable	0	0	228	228	419	419	419	419	419	419	419	419	419	419	419	419	419	419	419	419	
CT-Combustion Turbine	UR-Uranium	Studied Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
CC-Combined Cycle	Wind-Wind	Studied Peak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
C-Pulverized Coal	L-Landfill Gas	Studied Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
R-Renewable		Studied Unspecified	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
RE- Reciprocating Engine	S-Solar	Studied Base	0	0	0	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25	25	25	0
	OBG-Other Biomass Gas	TOTAL	0	0	909	1009	1200	1200	1225	1225	1225	1225	1225	1225	1225	1225	1225	1225	1225	1225	1225	1225	

	Existing	Committe	Planned	Studied	Unit Type	Behind M Utility	Behind M Utility	Fuel Type	Nameplat Yearly Val Nameplat	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	E				R			Wind	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
	E				R			Wind	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9
	E				R	Y		S	2.3	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31
	E				R			Wind	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8
		C			R			Wind	50.0	0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
	E				R	Y		S	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	E				R	Y		Wind	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	E				R	Y		S	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
	E				R	Y		Wind	1.3	1.32	1.3	1.3	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	E				R			L	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
	E				R			Wind	100.0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0
	E				R			Wind	100.0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	E				R			Wind	73.4	73.4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
	E				R	Y		S	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	E				R			Wind	30.0	30.0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0	0	0
	E				R			Wind	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	0.0	0.0	0.0
	E				R			Wind	59.4	59	59	59	59	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	E				R			Wind	80.0	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0
	E				R			Wind	80.0	80	80	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0
	E				R			Wind	3.0	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0
	E				R			Wind	80.0	80	80	80	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0
	E				R			Wind	73.1	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	0	0
	E				R			Wind	42.0	42	42	42	42	42	42	42	42	42	42	42	0	0	0	0	0	0	0	0	0
	E				R			Wind	75.0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	0	0
				S	R			Wind	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ind	E				R	Y		Wind	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
2)	E				R	Y		Wind	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Solar	E				R	Y		S	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	E				R	Y		S	0.1	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
2	E				R	Y		S	4.4	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38
	E				R	Y		S	0.1	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	E				R	Y		S	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
rk	E				R	Y		S	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
rk (2)	E				R	Y		S	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	E				R	Y		S	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	E				R	Y		S	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	E				R	Y		S	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	E				R	Y		S	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
j Solar	E				R	Y		S	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	E				R	Y		S	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
ar	E				R	Y		S	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	E				R	Y		Wind	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
e Solar LLC	E				R	Y		S	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
er Wind	E				R	Y		Wind	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	E				R	Y		S	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Solar	E				R	Y		S	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	E				R	Y		S	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
r	E				R	Y		S	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	E				R	Y		S	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	E				R	Y		S	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
zer Solar 1	E				R	Y		S	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
zer Solar 2	E				R	Y		S	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
nd		C			R	Y		Wind	8.0	0.0	0.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Solar	E				R	Y		S	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
oup Solar	E				R	Y		S	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
ea Wind Farm	E				R	Y		Wind	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
	E				R	Y		Wind	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
ject	E				R	Y		S	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind	E				R	Y		Wind	5.6	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64
		C			R	Y		S	8.5	0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
ge System		C				Y		ES	1.0	0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	E				R			BD	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
	E				R			L	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
	E				R			Wind	60.0	60	60	60	60	60	60	60	60	60	60	0	0	0	0	0	0	0	0	0	0
	E				R			Wind	40.5	40.5	41	41	41	41	41	41	41	41	41	41	0	0	0	0	0	0	0	0	0
	E				R			Wind	200.6	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	0	0
	E				R			Wind	400.0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	0	0	0
	E				R			Wind	160.0	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	0	0
	E				R			Wind	318.2	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	0	0
	E				R	Y		S	5.0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	0	0
		C			R			S	81.0	0	0	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
			P		R			S	419.0	0	0	228	228	419	419	419	419	419	419	419	419	419	419	419	419	419	419	419	419
	E				R			BD	4.0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	E				R			Wind	15.6	15.6	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	0	0	0
	E				R	Y		S	2.0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0
	E				R	Y		S	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
									2766.4	2198	2208	2525	2575	2765	2706	2706	2706	2626	2626	2486	2320	2320	2320	2320	2220	2218	1755	923	923

EXHIBIT 6.1
Statewide Renewable (Wind, Landfill, Solar and Biofuels) Generation by Nameplate

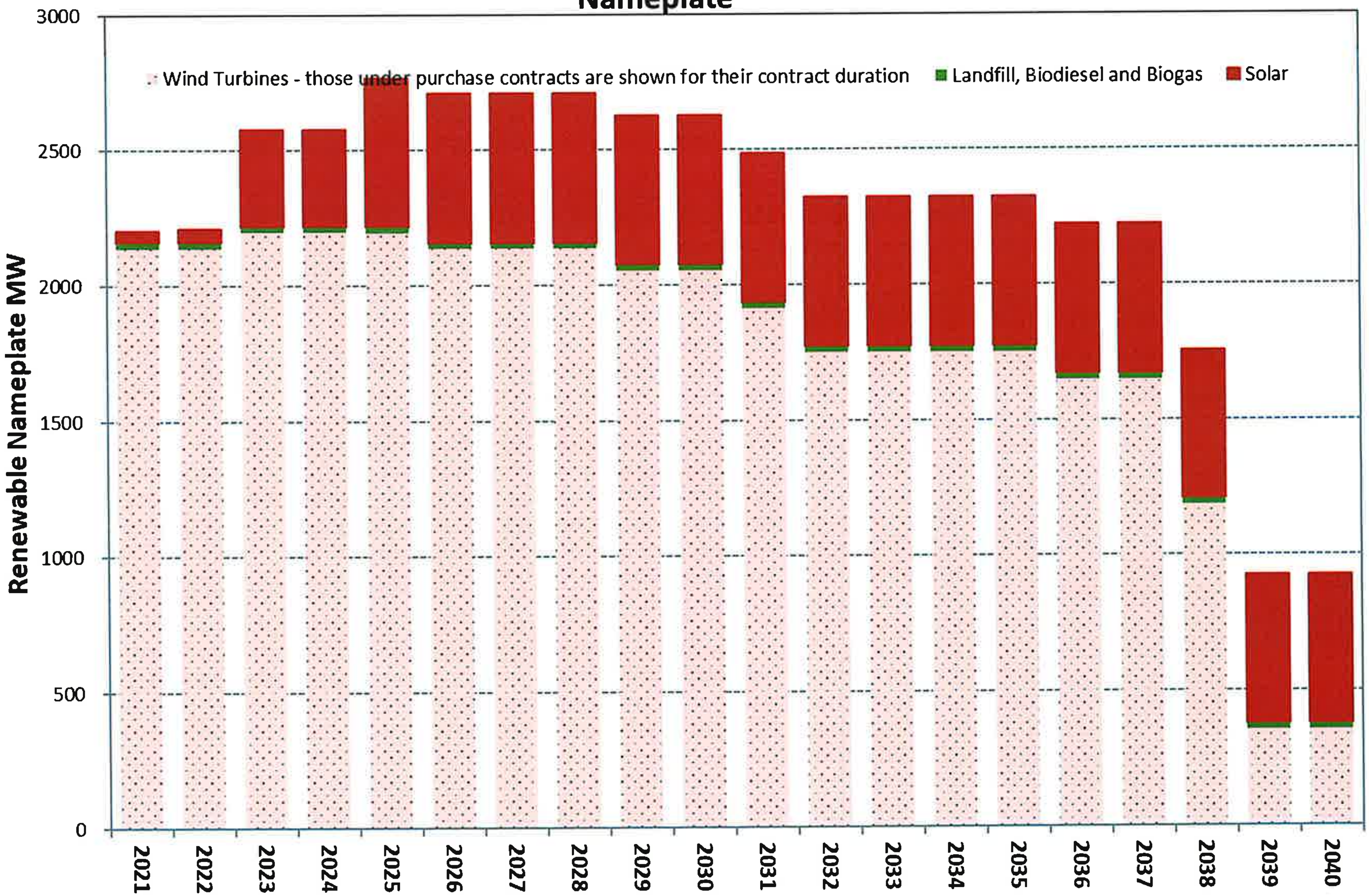


EXHIBIT 7

2021 Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
Towns/Districts	Cottonwood Wind NNPPD	I	WT	WND	2018	6.00	
	Cottonwood Wind SSC	I	WT	WND	2018	0.78	
	Cottonwodd Wind Farm	I	WT	WND	2018	1.61	
	S. Sioux City NG Generation	P	IC	NG	2020	0.00	
Towns/District							8.4
Falls City	Falls City #7	P	IC	NG/DFO	1972	2.00	
	Falls City #8	P	IC	NG/DFO	1981	5.00	
	Falls City	P	IC	NG/DFO	2018	9.00	
Falls City	Total						16.0
Fremont	Fremont #6	B	ST	SUB/NG	1958	15.50	
	Fremont #7	B	ST	SUB/NG	1963	21.00	
	Fremont #8	B	ST	SUB/NG	1976	82.00	
	CT	P	GT	NG/DFO	2003	36.00	
	Cottonwood Wind Farm	I	WT	WND	2018	2.04	
Fremont	Total						156.5
Grand Island	Burdick GT1	P	GT	NG/DFO	1968	13.00	
	Burdick GT2	P	GT	NG/DFO	2003	34.00	
	Burdick GT3	P	GT	NG/DFO	2003	34.00	
	Platte Generating Station	B	ST	SUB	1982	100.00	
	Prairie Breeze 3 Wind	I	WT	WND	2016	0.00	
Grand Island	Total						181.0
Hastings	CCC Hastings Wind	I	WT	WND	2016	0.00	
	DHPC-#1	P	GT	NG/DFO	1972	18.00	
	Hastings-NDS#4	P	ST	NG/DFO	1957	16.00	
	Hastings-NDS#5	P	ST	NG/DFO	1967	24.00	
	Whelan Energy Center #1	B	ST	SUB	1981	76.00	
	Whelan Energy Center #2	B	ST	SUB	2011	220.00	
Hastings	Total						354.0
LES	Arbuckle Mtn. Wind	I	WT	WND	2016	18.00	
	Buckeye Wind	I	WT	WND	2016	66.60	
	J St	P	GT	NG/DFO	1972	29.30	
	Landfill Gas	B	IC	LFG	2014	4.80	
	Laramie River #1	B	ST	SUB	1982	198.00	
	LES Community Solar	B	PV	SUN	2016	0.00	
	Prairie Breeze 2 Wind	I	WT	WND	2016	19.00	
	Rokeby 1	P	GT	NG/DFO	1975	70.50	
	Rokeby 2	P	GT	NG/DFO	1997	90.40	
	Rokeby 3	P	GT	NG/DFO	2001	94.20	
	LES Wind Turbines	I	WT	WND	1999	0.00	
	Terry Bundy	P	CS	NG/DFO	2003	118.50	
	Terry Bundy	P	GT	NG/DFO	2003	45.40	
	Walter Scott #4	B	ST	SUB	2007	102.70	
LES	Total						857.4
MEAN	Alliance #1	P	IC	DFO	2002	1.8373	
	Alliance #2	P	IC	DFO	2002	1.8570	
	Alliance #3	P	IC	DFO	2002	1.8078	
	Ansley #2	P	IC	NG/DFO	1972	0.8090	
	Ansley #3	P	IC	NG/DFO	1968	0.5410	
	Benkelman #1	P	IC	NG/DFO	1968	0.7850	
	Broken Bow #2	P	IC	NG/DFO	1971	3.0851	
	Broken Bow #4	P	IC	NG/DFO	1949	0.7891	
	Broken Bow #5	P	IC	NG/DFO	1959	0.9875	
	Broken Bow #6	P	IC	NG/DFO	1961	2.0383	
	Burwell#2	P	IC	NG/DFO	1962	0.7895	
	Burwell#3	P	IC	NG/DFO	1967	1.0215	
	Burwell#4	P	IC	NG/DFO	1972	1.2070	

EXHIBIT 7

2021 Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
MEAN (contd)	Callaway #3	P	IC	DFO	1958	0.4960	
	Callaway #4	P	IC	DFO	2004	0.3790	
	Chappell #5	P	IC	DFO	1982	0.8500	
	Crete #7	P	IC	NG/DFO	1972	6.1510	
	Curtis #1	P	IC	NG/DFO	1975	1.1983	
	Curtis #2	P	IC	NG/DFO	1969	1.0698	
	Curtis #4	P	IC	NG/DFO	1955	0.7979	
	Kimball #1	P	IC	NG/DFO	1955	0.59	
	Kimball #2	P	IC	NG/DFO	1956	0.51	
	Kimball #3	P	IC	NG/DFO	1959	0.67	
	Kimball #4	P	IC	NG/DFO	1960	0.65	
	Kimball #5	P	IC	NG/DFO	1951	0.41	
	Kimball #6	P	IC	NG/DFO	1975	2.17	
	Oxford #2	P	IC	NG/DFO	1952	0.67	
	Oxford #3	P	IC	NG/DFO	1956	0.86	
	Oxford #4	P	IC	NG/DFO	1956	0.63	
	Oxford #5	P	IC	DFO	1972	1.29	
	Pender #2	P	IC	NG/DFO	1973	1.861	
	Pender #3					0.651	
	Pender #4	P	IC	DFO	1961	0.788	
	Red Cloud #2	P	IC	NG/DFO	1953	0.630	
	Red Cloud #3	P	IC	NG/DFO	1960	0.970	
	Red Cloud #4	P	IC	NG/DFO	1968	0.994	
	Red Cloud #5	P	IC	NG/DFO	1974	1.606	
	Stuart #1	P	IC	NG/DFO	1965	0.734	
	Stuart #4	P	IC	NG/DFO	1996	0.809	
	West Point #2	P	IC	NG/DFO	1947	2.171	
	West Point #3	P	IC	NG/DFO	1959	1.113	
	West Point #4	P	IC	NG/DFO	1965	0.861	
	Wisner #4	P	IC	DFO	2008	1.000	
	Wisner #5	P	IC	DFO	2008	1.000	
MEAN	**Total**						**52.1**
NPPD	ADM	B	ST	SUB	2009	67.10	
	Ainsworth Wind	**I**	**WT**	**WND**	**2005**	**5.73**	
	Auburn #1	P	IC	NG/DFO	1982	2.00	
	Auburn #2	P	IC	NG/DFO	1949	1.00	
	Auburn #4	P	IC	NG/DFO	1993	3.00	
	Auburn #5	P	IC	NG/DFO	1973	3.00	
	Auburn #6	P	IC	NG/DFO	1967	2.00	
	Auburn #7	P	IC	NG/DFO	1987	5.00	
	Beatrice Power Station	I	CS	NG	2005	220.00	
	Belleville 4	P	IC	NG/DFO	1955	0.00	
	Belleville 5	P	IC	NG/DFO	1961	1.40	
	Belleville 6	P	IC	NG/DFO	1966	2.50	
	Belleville 7	P	IC	NG/DFO	1971	3.30	
	Belleville 8	P	IC	NG/DFO	2006	2.80	
	Broken Bow Wind	**I**	**WT**	**WND**	**2013**	**8.74**	
	Broken Bow II Wind	**I**	**WT**	**WND**	**2014**	**5.35**	
	Cambridge	P	IC	DFO	1972	3.00	
	Canaday	P	ST	NG	1958	99.30	
	Columbus 1	**B**	**HY**	**WAT**	**1936**	**15.00**	
	Columbus 2	**B**	**HY**	**WAT**	**1936**	**15.00**	
	Columbus 3	**B**	**HY**	**WAT**	**1936**	**15.00**	
	Cooper	**B**	**ST**	**NUC**	**1974**	**770.00**	

EXHIBIT 7

2021 Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
NPPD (contd)	**Crofton Bluffs Wind**	**I**	**WT**	**WND**	**2013**	**5.10**	
	David City 1	P	IC	NG/DFO	1960	1.30	
	David City 2	P	IC	DFO	1949	0.80	
	David City 3	P	IC	NG/DFO	1955	0.90	
	David City 4	P	IC	NG/DFO	1966	1.80	
	David City 5	P	IC	DFO	1996	1.33	
	David City 6	P	IC	DFO	1996	1.33	
	David City 7	P	IC	DFO	1996	1.34	
	Elkhorn Ridge Wind	**I**	**WT**	**WND**	**2009**	**6.25**	
	Emerson #2	P	IC	NG/DFO	1968	1.00	
	Emerson #3	P	IC	NG/DFO	1948	0.00	
	Emerson #4	P	IC	NG/DFO	1958	0.39	
	Franklin 1	P	IC	NG/DFO	1963	0.92	
	Franklin 2	P	IC	NG/DFO	1974	1.00	
	Franklin 3	P	IC	NG/DFO	1968	1.00	
	Franklin 4	P	IC	NG/DFO	1955	0.83	
	Gentleman 1	**B**	**ST**	**SUB**	**1979**	**665.00**	
	Gentleman 2	**B**	**ST**	**SUB**	**1982**	**700.00**	
	Hallam	P	GT	DFO	1973	41.95	
	Hebron	P	GT	NG	1973	41.50	
	Jeffrey 1 (CNPPID)	**B**	**HY**	**WAT**	**1940**	**0.00**	
	Jeffrey 2 (CNPPID)	**B**	**HY**	**WAT**	**1940**	**0.00**	
	Johnson I 1 (CNPPID)	**B**	**HY**	**WAT**	**1940**	**0.00**	
	Johnson I 2 (CNPPID)	**B**	**HY**	**WAT**	**1940**	**0.00**	
	Johnson II (CNPPID)	**B**	**HY**	**WAT**	**1940**	**0.00**	
	Kearney	**B**	**HY**	**WAT**	**1921**	**0.00**	
	Kingsley (CNPPID)	**B**	**HY**	**WAT**	**1985**	**41.67**	
	Laredo Ridge Wind	**I**	**WT**	**WND**	**2011**	**10.65**	
	Madison 1	P	IC	NG/DFO	1969	1.70	
	Madison 2	P	IC	NG/DFO	1959	0.95	
	Madison 3	P	IC	NG/DFO	1953	0.85	
	Madison 4	P	IC	DFO	1946	0.50	
	McCook	P	GT	DFO	1973	39.70	
	Monroe	**B**	**HY**	**WAT**	**1936**	**3.00**	
	North Platte 1	**B**	**HY**	**WAT**	**1935**	**12.00**	
	North Platte 2	**B**	**HY**	**WAT**	**1935**	**12.00**	
	Ord 1	P	IC	NG/DFO	1973	5.00	
	Ord 2	P	IC	NG/DFO	1966	1.00	
	Ord 3	P	IC	NG/DFO	1963	2.00	
	Ord 4	P	IC	DFO	1997	1.40	
	Ord 5	P	IC	DFO	1997	1.40	
	Sheldon 1	**B**	**ST**	**SUB**	**1961**	**104.00**	
	Sheldon 2	**B**	**ST**	**SUB**	**1965**	**115.00**	
	Spencer 1	**B**	**HY**	**WAT**	**1927**	**0.00**	
	Spencer 2	**B**	**HY**	**WAT**	**1952**	**0.00**	
	Springview Wind	**I**	**WT**	**WND**	**2012**	**0.29**	
	Steele Flats Wind	**I**	**WT**	**WND**	**2013**	**7.26**	
	Wahoo #1	P	IC	NG/DFO	1960	1.70	
	Wahoo #3	P	IC	NG/DFO	1973	3.60	
	Wahoo #5	P	IC	NG/DFO	1952	1.80	
	Wahoo #6	P	IC	NG/DFO	1969	2.90	
	Western Sugar	B	ST	SUB	2014	4.55	
	Wilber 4	P	IC	DFO	1949	0.78	
	Wilber 5	P	IC	DFO	1958	0.59	
	Wilber 6	P	IC	DFO	1997	1.57	
NPPD	**Total**						3,101.8

EXHIBIT 7

2021 Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
Wakefield	Wakefield 2	P	IC	NG/DFO	1955	0.54	
	Wakefield 4	P	IC	NG/DFO	1961	0.69	
	Wakefield 5	P	IC	NG/DFO	1966	1.08	
	Wakefield 6	P	IC	NG/DFO	1971	1.13	
Wakefield	**Total**						**3.4**
Wayne	Wayne 1	P	IC	DFO	1951	0.75	
	Wayne 3	P	IC	DFO	1956	1.75	
	Wayne 4	P	IC	DFO	1960	1.85	
	Wayne 5	P	IC	DFO	1966	3.25	
	Wayne 6	P	IC	DFO	1968	4.90	
	Wayne 7	P	IC	DFO	1998	3.25	
	Wayne 8	P	IC	DFO	1998	3.25	
Wayne	**Total**						**19.0**
Nebraska City	Nebraska City #5	P	IC	NG/DFO	1964	1.60	
	Nebraska City #6	P	IC	NG/DFO	1967	1.50	
	Nebraska City #7	P	IC	NG/DFO	1969	1.50	
	Nebraska City #8	P	IC	NG/DFO	1970	3.50	
	Nebraska City #9	P	IC	NG/DFO	1974	5.60	
	Nebraska City #10	P	IC	NG/DFO	1979	5.80	
	Nebraska City #11	P	IC	NG/DFO	1998	4.00	
	Nebraska City #12	P	IC	NG/DFO	1998	4.00	
Nebraska City	**Total**						**27.6**
NELIGH	**Neligh**	**P**	**IC**	**OBL**	**2012**	**1.90**	
	Neligh	**P**	**IC**	**OBL**	**2012**	**1.90**	
	Neligh	**P**	**IC**	**OBL**	**2012**	**1.91**	
	Neligh	**P**	**IC**	**OBL**	**2012**	**0.41**	
Neligh	**Total**						**6.1**
OPPD	Cass County #1	P	GT	NG	2003	162.00	
	Cass County #2	P	GT	NG	2003	161.80	
	Elk City Station #1-4	**B**	**IC**	**LFG**	**2002**	**3.09**	
	Elk City Station #5-8	**B**	**IC**	**LFG**	**2006**	**2.92**	
	Flat Water Wind	**I**	**WT**	**WND**	**2011**	**13.10**	
	Grande Prairie Wind	**I**	**WT**	**WND**	**2016**	**64.50**	
	Jones St. #1	P	GT	DFO	1973	61.20	
	Jones St. #2	P	GT	DFO	1973	62.20	
	Nebraska City #1	**B**	**ST**	**SUB**	**1979**	**654.30**	
	Nebraska City #2	**B**	**ST**	**SUB**	**2009**	**691.00**	
	North Omaha #1	B	ST	NG	1954	64.80	
	North Omaha #2	B	ST	NG	1957	90.80	
	North Omaha #3	B	ST	NG	1959	86.00	
	North Omaha #4	**B**	**ST**	**SUB/NG**	**1963**	**120.10**	
	North Omaha #5	**B**	**ST**	**SUB/NG**	**1968**	**216.20**	
	Petersburg Wind	**I**	**WT**	**WND**	**2012**	**8.00**	
	Prairie Breeze Wind	**I**	**WT**	**WND**	**2014**	**43.10**	
	Sarpy County #1	P	GT	NG/DFO	1972	55.40	
	Sarpy County #2	P	GT	NG/DFO	1972	55.90	
	Sarpy County #3	P	GT	NG/DFO	1996	107.80	
	Sarpy County #4	P	GT	NG/DFO	2000	48.70	
	Sarpy County #5	P	GT	NG/DFO	2000	47.90	
	Sholes Wind	**I**	**WT**	**WND**	**2019**	**58.30**	
	Tecumseh #1	P	IC	DFO	1949	0.60	
	Tecumseh #2	P	IC	DFO	1968	1.40	
	Tecumseh #3	P	IC	DFO	1952	1.00	
	Tecumseh #4	P	IC	DFO	1960	1.20	
	Tecumseh #5	P	IC	DFO	1993	2.30	
OPPD	**Total**						**2,886.6**
SCRIBNER	**Scribner #1**	**P**	**IC**	**OBL**	**2020**	**2.00**	
	Scribner #2	**P**	**IC**	**OBL**	**2020**	**2.00**	
							4.0
Nebraska Grand Total						**TOTAL**	**7,672.9**

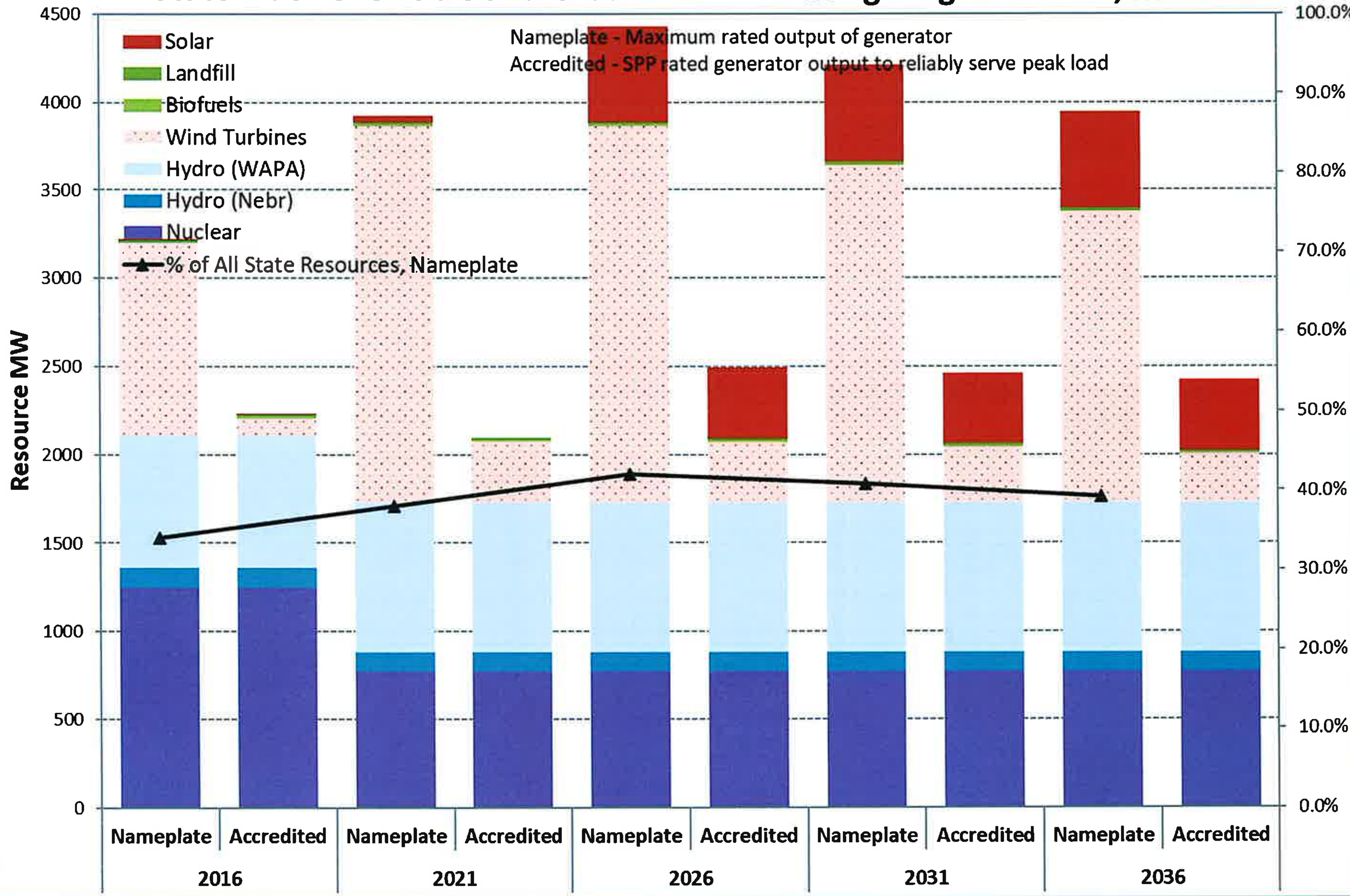
Duty Cycle
B-Base
I-Intermediate
P-Peaking

Fuel Type*
NUC-Uranium
NG-Natural Gas
DFO-Distillate Fuel Oil
SUB-Subbituminous Coal
OBL-Biodiesel
WAT-Hydro
LFG-Landfill Gas
WND-Wind

Unit Type*
IC-Internal Combustion, Reciprocating
ST-Steam Turbine, does not include combined cycle
GT-Combustion Turbine, including aeroderivatives
CS-Combined Cycle, single shaft (combustion turbine and steam turbine share single
CA-Combined Cycle, Steam part
CT-Combined Cycle, Combustion Turbine part
HY-Hydro
PV-Photovoltaic
WT-Wind Turbine
FC-Fuel Cell
WH-Waste Heat, used for combined cycle ST without supplemental firing

EXHIBIT 7.1

Statewide Renewable and Greenhouse Gas Mitigating Resources, MW



APPENDIX NO. 21

Nebraska Public Power's Response to "Nebraska Public Power's Competitiveness in the Regional Energy Market"

November 12, 2016

NPPD's initial response to "Nebraska Public Power's Competitiveness in the Regional Energy Market" (Report)

The Report is right on a few key facts and mistaken on others but wrong in its conclusions and recommendations.

1) Nebraska's public power generators compete effectively in the SPP Integrated Market.

- The Report correctly notes that the SPP Integrated Market (SPP IM) is based on the marginal cost of electricity—basically the cost of the fuel to produce the electricity and any variable operations and maintenance (VOM) costs due exclusively to generating the next unit of electricity. The SPP market is not designed to pay for other costs of generation such as labor, debt, capital, insurance, taxes, other administrative and general costs and any other costs associated with owning a generating plant. SPP's market, like most other regional electricity markets, is designed to collect marginal costs only for a majority of the electricity sold and assumes all other costs of owning the generating facilities are collected through electric rates from customers.

- The SPP IM generally ensures the lowest total variable cost, which is made up almost exclusively of fuel costs, for the entire system on a minute-to-minute basis throughout the year. The SPP IM, as currently configured, does not address how much new generation capacity should be added, when new capacity should be added, and what fuel source or sources should be used when generation is added. The SPP IM also must consider system reliability requirements which include: voltage support, management of operating reserves, and the "headroom" (energy available if forecasts are incorrect) needed, especially when high levels of renewable generation are online.

- The Report generally acknowledges this pricing concept and then completely contradicts it by claiming Nebraska's Public Power generators are not recovering their full production costs, let alone debt and capital from the market. Of course we don't. Neither does nearly anyone else in the SPP footprint, including wind generators when they create negative prices due to production tax credits, which are taxpayer subsidies that are often greater than the marginal cost of the electricity. The Report implies Nebraska's utilities are uniquely challenged because marginal costs are not fully recovering total production costs, but no other utility in SPP (or any other RTO market, whether investor owned, public power or cooperative) expects to cover its entire production costs, let alone total generation costs from a market designed to pay for the value of fuel and VOM only.

- As the Report notes on p.3, the "market determines the winners and losers of generation based on the marginal cost of production which does not include any fixed costs." Nevertheless, utilities with low fuel costs, such as NPPD, can make additional revenues in the market to cover all or a part of their fixed costs, if their marginal costs are below the market clearing price which changes frequently throughout the day. Wind and hydro have no fuel cost. Nuclear fuel is the next lowest cost per megawatt-hour. Powder River Basin coal from Wyoming is typically the next lowest fuel cost, especially for Nebraska power plants since they are relatively close to the coal production compared to other states in the SPP where the transportation costs for the fuel are significantly higher. Natural gas is typically the next lowest marginal cost depending on the type of natural gas plant. Natural gas can be cheaper than coal when power plants have long distances for their coal shipping costs. Nebraska has a locational advantage in this regard. An examination of NPPD's 2015 Annual Financial Report, which the Report cites several times, shows NPPD's fuel costs per megawatt-hour of production are well below the marginal cost prices in the market and the average price NPPD received for surplus sales to the SPP. The Report fails to acknowledge these key facts supporting NPPD's competitiveness in the SPP market.

- The Report states Nebraska has a higher coal and nuclear mix in comparison to SPP's generation mix. But based on the fuel cost discussion above and table 1.2 in the Report, the marginal costs for coal and nuclear are considerably less than that of "cheap" natural gas/combined cycle. Total generation costs can also be lower depending on particular generating unit efficiencies and the price of natural gas which continues to show much greater volatility than coal or nuclear fuel. Natural gas prices can also experience sharp increases due to delivery constraints during high demand periods.

- Finally, NPPD would not be selling so much power into the market beyond the quantities produced for its own customers, if its generating resources were not competitive on marginal costs. During times when NPPD loads are lower, the market typically benefits from additional low cost energy that NPPD generators can provide to others. NPPD often generates above its load when baseloads are at minimums. In fact, 30% of NPPD's 2015 sales were above customer and contracted power needs thus proving the market values NPPD's generation fleet.

2) Nebraskans have benefitted from the $1 billion dollar savings SPP has estimated since the market went live in March of 2014.

- There are three basic sources of benefits. First, by creating a consolidated balancing area among NPPD and the other balancing area utilities, there is less generation needed to address the unexpected loss of generation or other supply and demand events than was needed when there were 16, separate balancing areas. Spreading these risks over a larger footprint with one balancing area reduces the total cost of managing these issues.

- Second, the Integrated Market has reduced the overall cost of generation by serving the entire market with the lowest cost fuel based on marginal costs.

- Third, the growing physical footprint of SPP increases opportunities to provide NPPD's low fuel cost energy to more customers and bring revenues above NPPD's marginal costs back to NPPD's customers to cover a portion of fixed costs.

3) Nebraska's electric rates, including industrial, are competitive.

- The Report's principal investigator is well aware the U.S. Energy Information Administration data on industrial revenue per kilowatt hour for Nebraska is significantly skewed upward by Nebraska's extensive amount of seasonal, agricultural irrigation pumping with electricity. Nebraska leads the Nation in irrigated acres and a significant percent of the acres rely on electricity, rather than fossil fuel to pump the water. NPPD is required to have resources available during the summer irrigation season, which has much higher load levels than other periods of the year. This seasonal load represents a much different resource need than most other entities in SPP.

- The EIA places irrigation in the industrial customer category. However, those knowledgeable about the characteristics of building infrastructure and other costs to serve seasonal irrigation versus the characteristics of a typical industrial customer operating 24 x 7, understand the high amount of irrigation served by electrically powered pumping has a substantial impact on the average revenue per kWh, making Nebraska appear far less competitive than it actually is on true industrial rates. Dr. Goss, the principal investigator for the Report, was provided substantial evidence on this topic in response to a report he authored almost one year ago on the competitiveness of public power where he failed to recognize the impact of EIA including irrigation customers in the industrial class. Repeating misleading conclusions a year latter is yet another example of the fundamental weaknesses of the Report.

- NPPD's average revenue per kilowatt hour for industrial rates for 2015 was 5.64 cents per kWh. This is well below the national average which was 6.91 cents per kWh. In addition to competitive industrial rates, Nebraska's 2015 residential rates were 19.3% below the national average; commercial rates were 22.7% below; and total (all classes) rates were 16.8% below the national average. Many other Nebraska utilities have very competitive industrial rates for "typical" industrial customers.

4) Wind energy is reducing the amount of generation at coal-fired power plants, but the dispatchable capacity provided by Gerald Gentleman Station and Sheldon Station is essential to the market.

- Wind generation is clearly increasing. Wind energy has no fuel cost and is receiving a tax subsidy for each megawatt hour produced which can exceed the marginal cost of energy, especially during low load periods and off peak hours. Wind generation is displacing some coal generation, yet coal remains the largest source of energy in the SPP footprint. NPPD is developing strategies to address keeping its coal generation competitive in this changing fuel mix. Other utilities with coal plants which are not as large and efficient as a Gentlemen Station, or that have much higher fuel costs, may reach a point where it is no longer cost effective to operate them.

- The larger the percentage of wind in SPP, the more challenging it becomes to "chase the wind" with certain conventional generation facilities which were designed to run at relatively constant levels of generation. While wind energy will continue to expand, dispatchable capacity must be available when the wind isn't blowing or can't be controlled to blow more to increase generation when the customers need it. There is a cost to having back-up generation. There are also fundamental needs to maintain voltage and other operational characteristics of the electric grid that cannot be met with wind generation.

- The Report casually assumes large-scale storage will back up wind, but there is no credible timeframe or cost estimate to support such a conclusion. A true bus bar cost of wind would include the cost of energy storage or the cost to have other types of generation available on short notice, such as natural gas, to cover times when renewables do not perform as projects. In short, wind cannot be the only source of generation. It only works in the electric system if there is a nearly equivalent amount of available and reliable generation ready to operate when wind is not generating. Conventional generation does not have this limitation.

- The addition of increasing amounts of wind generation, due to tax incentives, has contributed to lower market prices for energy in the SPP IM, as well as increased volatility of those prices. Wind generation alone is not capable of following and serving load in the integrated market. All types of generation are needed, including baseload, carbon-free nuclear and reliable coal units.

- The addition of renewables also affects reliability, which requires baseload or other generating resources (e.g. combined-cycle and peaking units) when the renewables are not producing. As more new renewable generation is proposed, there is a need to ensure reliability with dependable resources necessary to meeting demand.

- While coal use is trending down nationally and in the SPP footprint, no credible source is suggesting coal will be eliminated as a generating source in the next several decades. Even President Obama's Clean Power Plan projects 30% of the Nation's electricity coming from coal in 2030. Since the West Coast and Northeast use nearly no coal, the average amount of coal in other regions will be higher than 30%. As the Report's Figure 1.2 on page 5 notes, nuclear and coal both have lower marginal costs than natural gas. Without the majority of these units, reliability will be a serious challenge in the SPP. In the last four years, coal-fired generation has provided more than 50 percent of all the electricity produced in SPP.

5) States with retail choice have higher electric rates.

- There is no clear explanation within the report as to where the "estimated" $250million in annual savings would be derived through retail choice. The authors state Nebraskans could save between 15 and 20 percent on their bills but without concrete evidence to prove how.

- The Report focuses on SPP's low-cost generation yet fails to acknowledge that none of the end-use customers served within the SPP footprint have retail choice. Figure 3.2 on page 20 of the Report indicates 17 states have adopted some form of retail choice, meaning end-use customers can choose their own power supplier. It does not acknowledge that eight retail choice states have suspended or rescinded all or parts of their programs. Nor does it acknowledge that all 17 of the states have higher average residential prices per kilowatt-hour than Nebraska, with a vast majority of them having residential average prices ranging from more than 20% higher to nearly double the price in Nebraska. Is this what Nebraskans really want?

- The Report also completely ignores the transition issues which have challenged states with retail choice. One transition issue would involve the divestiture of Nebraska's generation resources which were built and are maintained with ratepayer dollars. Replacing public power-owned assets with private assets or new, privately owned resources comes with new and different cost risks to ratepayers. The Report asserts shareholders will shoulder the risk instead of ratepayers. In practice, however, if this risk is placed upon shareholders, the company may cease to exist, leaving ratepayers with higher cost options. The cost of generation will always be borne by the ratepayers or taxpayers (e.g. taxpayers via production tax credits).

- Another issue not covered in the Report is the oversight necessary for transitioning to a retail choice business model. The initiative would require significant restructuring of the SPP IM and new regulatory responsibilities for state government in Nebraska to properly regulate the new market and its participants. Nebraska, like the majority of states, has "regulated markets" where the local utility has the legal obligation to serve all of the customers in its retail distribution area with rates that are cost-based and generally fair, reasonable and nondiscriminatory. Unlike other states, Nebraska electric customers also elect their power district board member, city council member or cooperative board member whose responsibilities include setting rates, making policy decisions and holding the utility accountable to the ratepayers it serves.

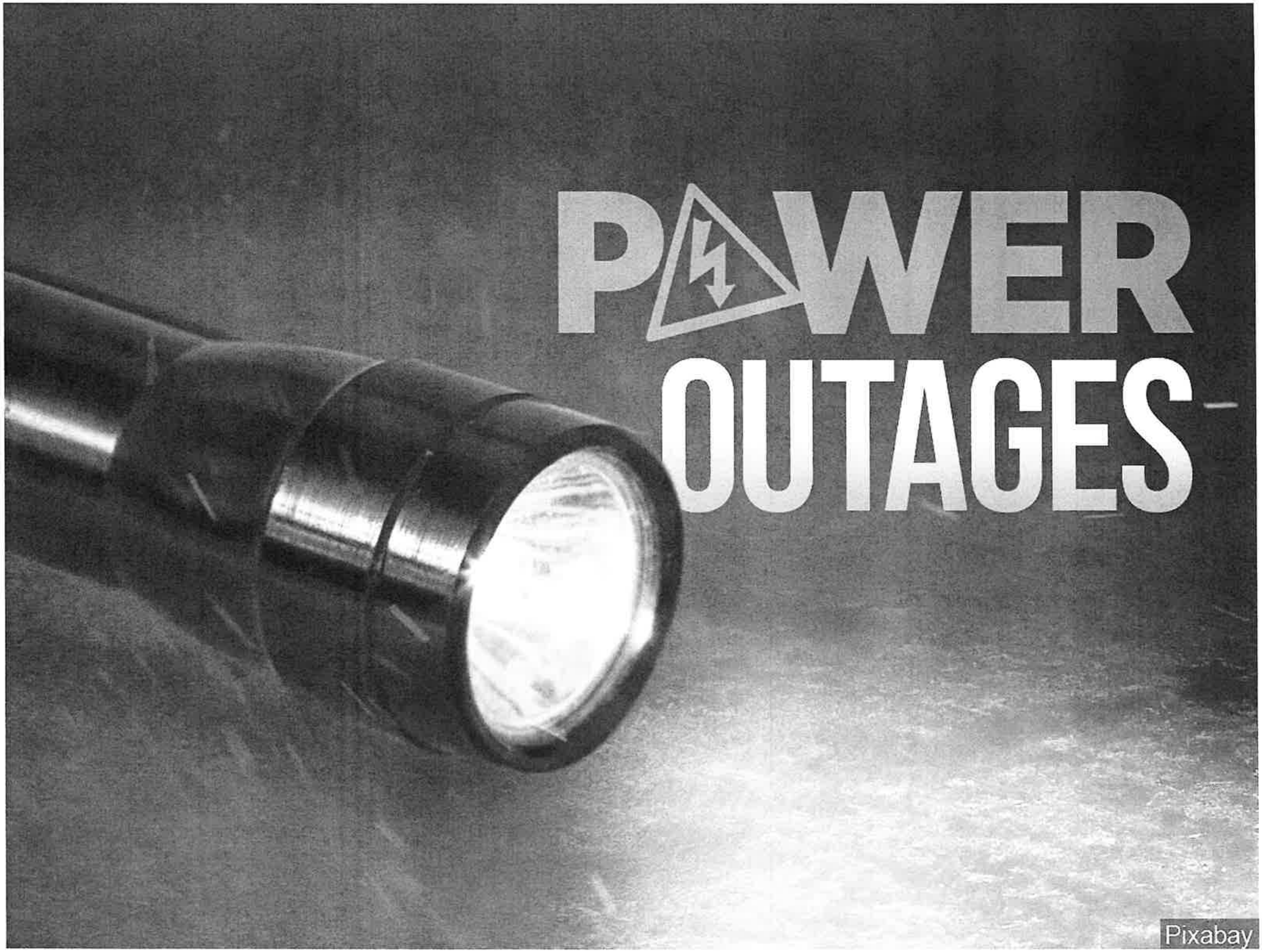
APPENDIX NO. 22

Nebraska Unplugged: Power Outages Sweep Across the State

Nebraska Unplugged: Power outages sweep across the state

February 17, 2021 8:00 am by (https://www.klkntv.com/bios/ashley-springman/)

22


POWER
OUTAGES
Pixabay

LINCOLN, Neb. (KLKN) — Across Nebraska, city electricity agencies have been purposely pulling the plug on power due to un-expected demand.

With temperatures remaining dangerously low, Nebraskans are staying inside with their heater on high, putting a strain on their regional power district.

Below are the cities experiencing electricity limitations Monday and Tuesday.

Giltner, Stockham, east of Doniphan, and the Aurora I-80 area

At 9:25 am, Southern PPD announced the next wave of rolling outages has been implemented in the following areas:

SouthernPPD
@southernppd

The next wave of rolling outages has just been implemented, affecting customers east of Doniphan, including Giltner and Stockham, and the Aurora I-80 area. Also customers in northern Phelps County--south of Elm Creek. We anticipate one hour, we will advise you of changes.

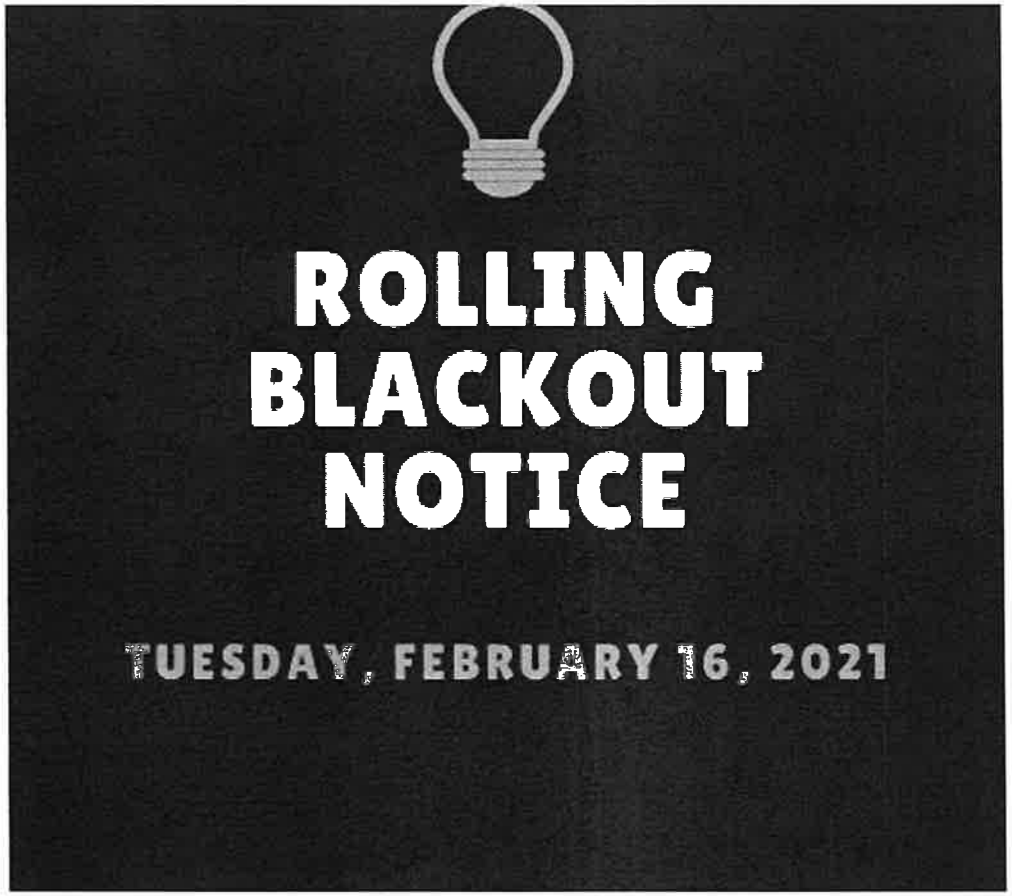
9:26 AM · Feb 16, 2021

Share this Tweet

Tweet your reply

Beatrice

City of Beatrice, Nebraska - Municipal Government
about 7 months ago



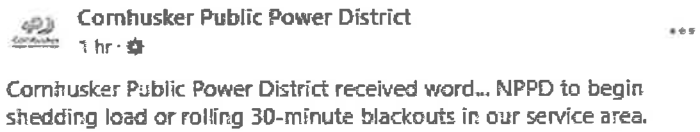
2/16/2021 | 6:25 a.m.

South and east Beatrice is expected to be without power within the hour.

Southwest Power Pool (SPP) has ordered Nebraska Public Power District (NPPD) to shed load and our breaker is second in line today.

The outage is expected to last approximately 30 minutes.
Stay tuned to our social media, website, and local media outlets for further updates as they are available.

Columbus and Cedar Rapids- Cornhusker Public Power District (https://cornhusker-power.com/)



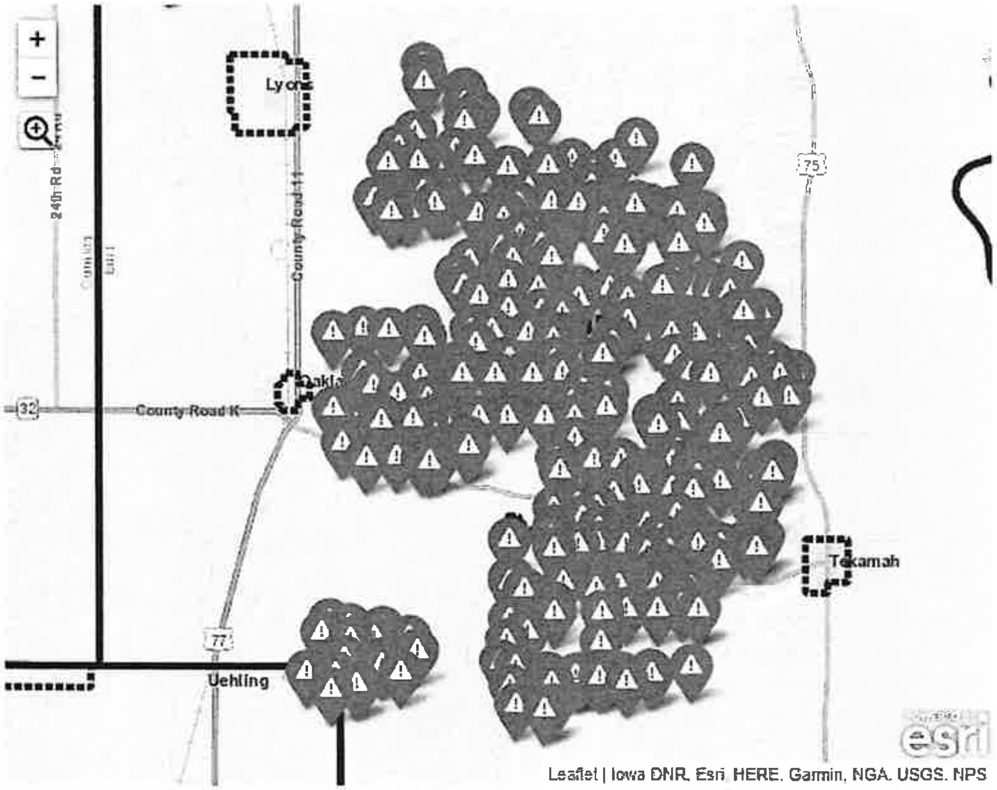
Cornhusker Public Power District
1 hr ·

Cornhusker Public Power District received word... NPPD to begin shedding load or rolling 30-minute blackouts in our service area.

(https://www.klkntv.com/content/uploads/2021/02/screenshot-2021-02-16-075652.jpg)

Craig, Tekamah- Burt County Public Power District (http://www.burtcoppd.com/index.asp)

Burt County Public Power District
about 7 months ago



UPDATE: This outage has been restored at 9:16 am.

We just received notification from NPPD that more of our breakers will be tripped to be included in the next rolling outage. This will affect our Craig Substation. This outage occurred at 7:57 am and should only last 30 minutes.

11 5 18

David City- Butler Public Power District (https://butlerppd.com/#)

Butler Public Power District
about 7 months ago

Update @ 9:20am, we are getting reports that power should be restored. Again, we apologize for the delay but it is out of our hands. We have not heard a reasoning of why it took longer than expected.

Update @ 9:15am. We understand this is taking longer than expected. We were told by NPPD that it would last 30 minutes. We realize we are going on over an hour. We are trying to get an update for you. As soon as we do, it will be updated here. Unfortunatly, this is out of ... See More

13 9 16

Elkhorn- Elkhorn Rural Public Power District (https://erppd.com/about-erppd/service-area/)

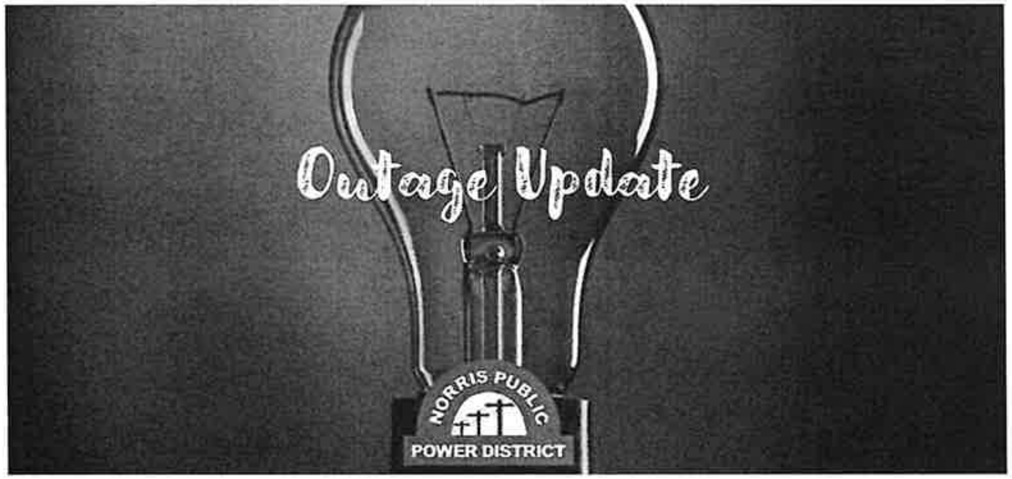
Elkhorn Rural Public Power District
about 7 months ago

10:12 a.m. - They are restoring all power for now.
9:00 a.m. We are being told that they will continue to shed load. The SPP/NPPD will be rotating through the state with outages up to 45 minutes in length. Since they are adjusting the load in real time, we do not get notice to which circuits will be affected until they are shut off. Please continue to conserve electricity and take necessary steps to be safe - for example: have cell phones charged, gas tanks filled, extra... See More

6 1 33

Norris- Norris Public Power District (https://norrisppd.com/)

Norris Public Power District
about 7 months ago



The next group of scheduled SPP rolling blackouts in the Norris territory are the areas of Bruning, Daykin and Hebron. Time to be determined by SPP without notice.

10 19 35

Omaha- Omaha Public Power District (https://www.oppd.com/)

Controlled outages were directed this morning by the Southwest Power Pool. There is the potential for continued...

Posted by Omaha Public Power District (https://www.facebook.com/OmahaPublicPowerDistrict/) on Tuesday, February 16, 2021 (https://www.facebook.com/OmahaPublicPowerDistrict/photos/a.189048477873040/3782415591869626/?type=3)

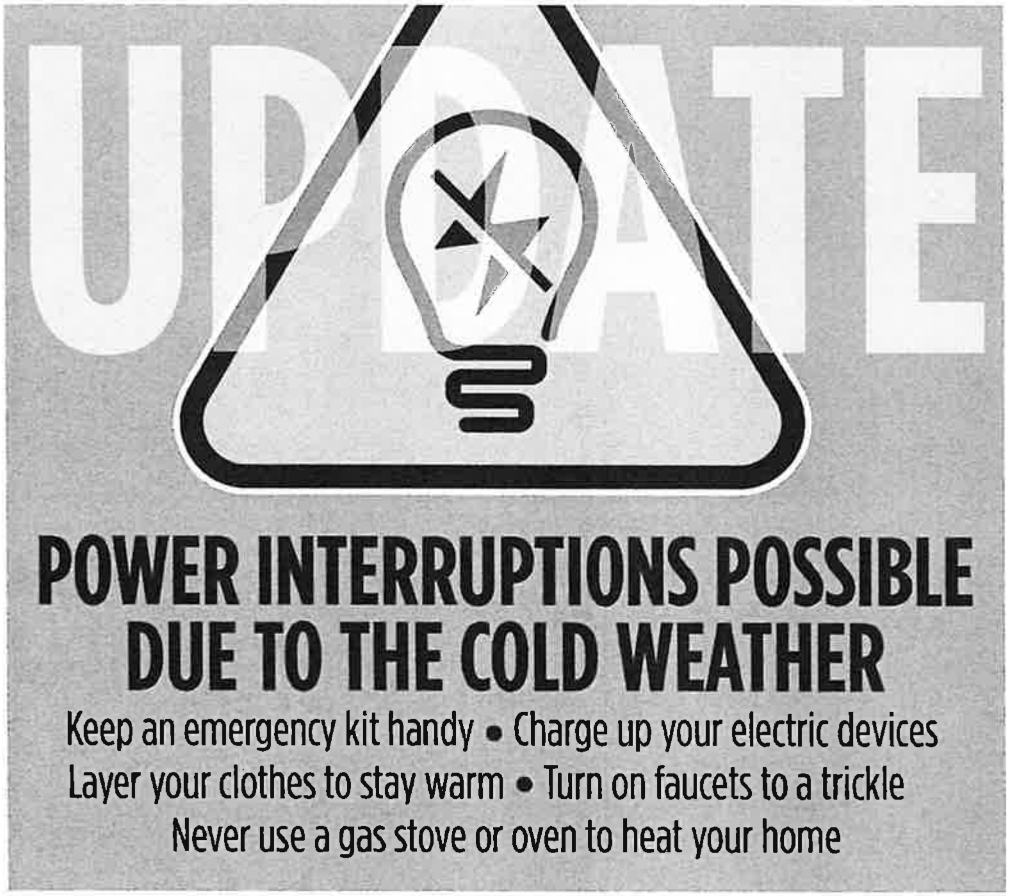
Platte Center, Duncan, and Lindsay- Loup Power District (http://www.loup.com/)

This Facebook post is no longer available. It may have been removed or the privacy settings of the post may have changed.

Help Center

York and Seward- Nebraska Public Power District (https://www.nppd.com/)

Nebraska Public Power District
about 7 months ago

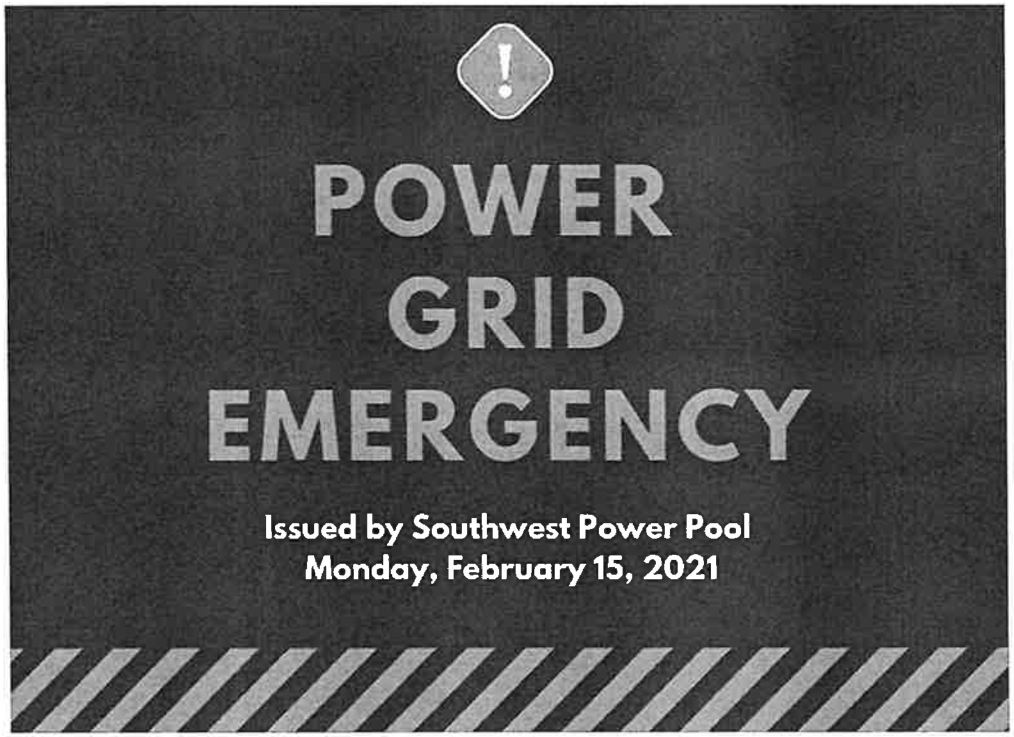


TUESDAY AM UPDATE: To maintain system reliability, we have just been informed by SPP that we need to do emergency coordinated interruptions of service. These 30-minute interruptions of service occur in real-time, so we have very little, if any, notice as to where these interruptions will take place. This is done to prevent longer, uncontrolled outages. If you experience a controlled outage, it should only last approximately 30 minutes.

MONDAY, FEBRUARY 15

Beatrice

City of Beatrice, Nebraska - Municipal Government
about 7 months ago



"Persistent and extreme cold weather has led to region-wide electricity use that exceeds available generation across the Southwest Power Pool (SPP) service territory. At 10:08 a.m. central time on Monday, Feb. 15 the grid operator declared an Energy Emergency Alert (EEA) Level 3, signaling that its operating reserves are below the required minimum. SPP has directed its member utilities to be prepared to implement controlled interruptions of service if necessary."
The above st... See More

21 122 221

Bellevue

Loup Power District
about 7 months ago

Please try to conserve energy the next few days by turning down your thermostat a few degrees, unplugging devices and appliances you aren't using, and reducing the use of large appliances like washers/dryers and ovens.

“In our history as a grid operator, this is an unprecedented event and marks the first time SPP has ever had to call for controlled interruptions of service,” said Lanny Nickell, SPP’s executive vice president and chief operating officer. “It’s a last resort that we understand puts a burden on our member utilities and the customers they serve, but it’s a step we’re consciously taking to prevent circumstances from getting worse."

OMAHA.COM

First rolling blackouts hit Nebraska after cold snap spikes p…

The Lincoln Electric System was among the first local utilities to announce…

44 **Comment** **106**

Crete

(https://www.klkntv.com/content/uploads/2021/02/screenshot-2021-02-15-141925.jpg)

Grand Island & Hastings

Southern Public Power District
about 7 months ago

The Southwest Power Pool has declared Energy Emergency Alert Level 3. We are beginning to see that roll out into our service region. At this time, we are seeing 30-minute interruptions of power. We are not aware of a schedule for these interruptions, but we are working with NPPD to keep up to speed as this situation evolves today. Stay tuned, we will do our best to keep you all informed.

57 **18** **235**

Holdrege

UPDATE:

The City of Holdrege has most of the town's power back, after an outage that took out two thirds of the town's electricity early this morning.

Posted by NTV News (https://www.facebook.com/ntvnews/) on Monday, February 15, 2021 (https://www.facebook.com/ntvnews/posts/10159177733886354)

Norris

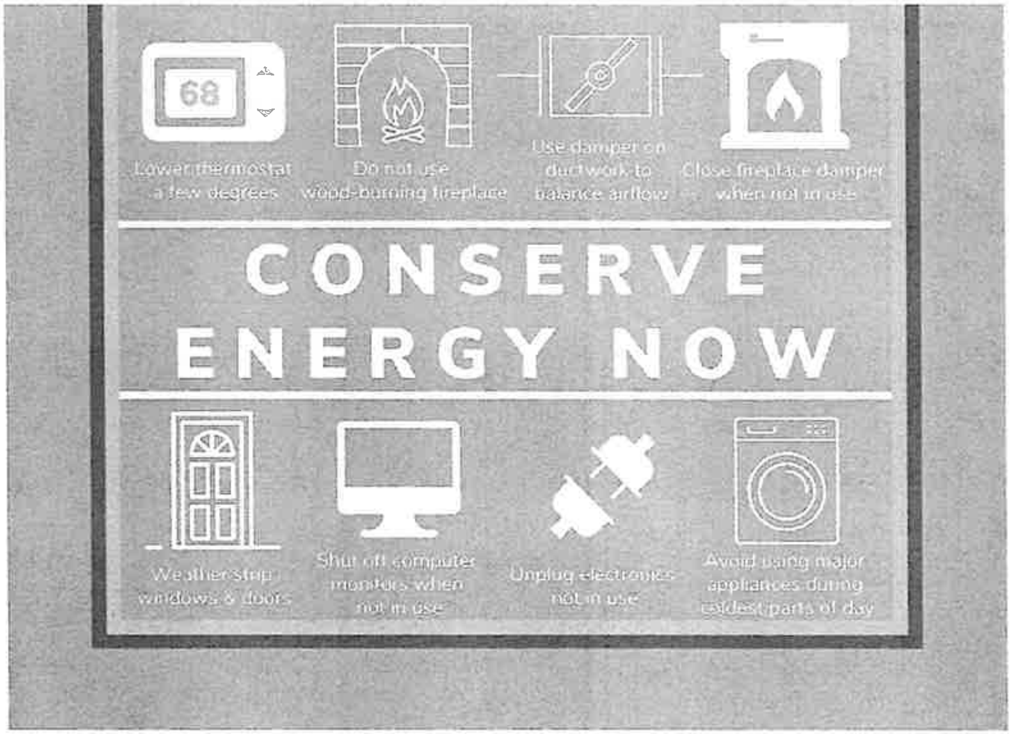
Norris Public Power District
about 7 months ago

Norris has been informed by Nebraska Public Power District that they are being directed to begin shedding load. The first round of load is being shed for 30 minutes, and will be followed by another group for the following 30 minutes. We appreciate your patience and understanding.

44 143 341

Omaha

Omaha Public Power District
about 7 months ago



We need your help conserving energy—NOW. The bitter cold temperatures have increased demand for energy across the Plains region, even south into Texas and Oklahoma. Much as it does in summer, high demand can put additional strain on our system. We are seeing similar effects now, only this time with record cold instead of heat.

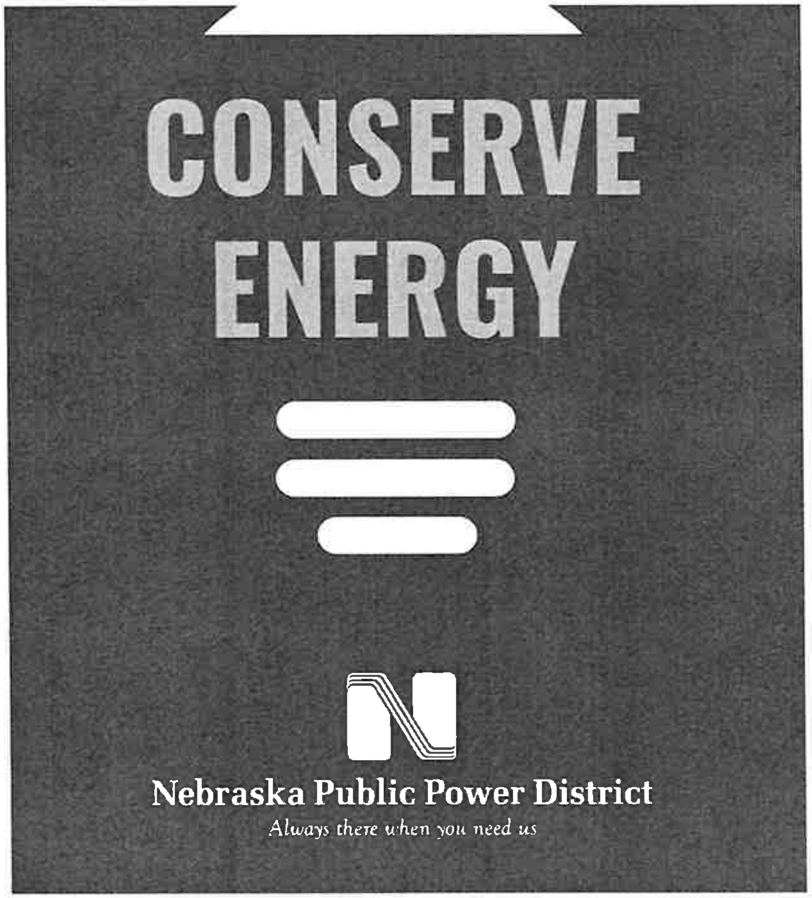
The Southwest Power Pool (SPP), the regional transmission organization who oversees the power grid for its members – of which OPPD is one – is asking all member organizations to begin energy conservation measures by 11:59 p.m., Sunday. SPP declared an Energy Emergency Alert as record cold conditions settled across the region, and is seeking help from its member organizations to balance what is currently peak demand for winter months.

Learn more at http://ow.ly/RbS450DA83F.

72 **76** **421**

York & Seward

Nebraska Public Power District
about 7 months ago



We are asking customers to conserve energy. The record cold forecast is putting a high demand on the electrical system. Follow these tips to reduce your energy usage:

• Turn down thermostats to 68 degrees and lower at night.
• Close shades and blinds.
• Turn off and un-plug non-essential lights and appliances.
• Close the fireplace damper when not in use.... See More

174 53 771

Rotating Planned Outages

Due to a high demand for energy, LES is doing rotating power outages. Let us know if you've been affected!

Is your power out? *

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APPENDIX NO. 23

"Nebraska Public Power's Competitiveness in the Regional Market"

Produced by Wind is Water

Dr. Ernie Goss, Investigator

Nebraska Public Power's Competitiveness in the Regional Energy Market

Produced for Wind is Water Foundation

December 12, 2016

Goss & Associates Economic Solutions
www.gossandassociates.com
The Goss Institute
Ernest Goss, Principal Investigator
600 17th Street, Suite 2800 South
Denver, Colorado 80202-5428
303.226.5882

Ernest Goss, Ph.D.
ernieg@creighton.edu
Jeffrey Milewski, M.S.
jmilewski@gossandassociates.com

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Preface

Nebraska Public Power's Competitiveness In the Regional Energy Market

The subsequent analysis was prepared for Wind is Water by Ernest Goss, Ph.D., Principal Investigator, and Jeff Milewski of Goss & Associates Economic Solutions. Findings remain the sole property of Wind is Water Foundation and may not be used without prior approval of this organization. Any errors or misstatements contained in this study are solely the responsibility of the authors.[1] The authors' biographies are provided in Appendix G. Please address all correspondence to:

Goss & Associates, Economic Solutions, LLC

Goss & Associates

Principal Investigator: Ernie Goss, Ph.D.
ernieg@creighton.edu
www.gossandassociates.com
Creighton University
Department of Economics
http://business.creighton.edu/economicoutlook
The Goss Institute for Economic Research

600 17th Street, Suite 2800 South
Denver, Colorado 80202-5428
402.280.4757 - 303.226.5882

Goss & Associates thanks Wind is Water Foundation for their assistance in providing data for this study. However, any errors, omissions, or misstatements are solely the responsibility of Goss & Associates and the principal investigator.

Goals of the study

The goal of this study was to examine how Nebraska's power industry operates within the Southwest Power Pool, particularly the integrated marketplace, and to determine whether Nebraska's Public Power Model is adequately serving the ratepayer.

Specific goals of the study are to:

- Determine whether increased competition and choice in Nebraska's power industry leads to cheaper sources of electricity and better rates for consumers.
  - If so, explore how increasing competition and choice affect Nebraska's generating utilities, consumer-utilities, and ratepayers.
- Examine how federal tax credits for renewables and environmental regulations, particularly the new Clean Power Plan, would affect Nebraska's public power utilities.
- Investigate how Nebraska's public power structure restricts choice. What disincentivizes private capital from investing in Nebraska's electricity sector?
- Determine whether legislative changes would help increase transparency and promote greater choice in the electric industry in Nebraska.

[1] This study was completed independent of Creighton University. As such, Creighton University bears no responsibility for findings or statements by Ernie Goss, or Goss & Associates, Economic Solutions.

Executive Summary

Nebraska Public Power's Competitiveness In the Regional Energy Market

- Since the implementation of the SPP Integrated Market (IM) in March 2014, electricity prices have trended downward due to the addition of wind generation and low natural gas prices. Because of the high cost of production at some plants in Nebraska, ratepayers have not fully benefited from the more than $1 billion saved by lower electricity prices from the SPP IM. Until Nebraska's generation costs are reduced, ratepayers will not benefit from the lower prices in the SPP IM.
- The cost effectiveness of Nebraska's public power generation is currently at risk in the SPP IM. There are two main reasons for this: (1) low natural gas prices; and (2) additional wind generation in the SPP footprint.
- The financial risk to ratepayers in owning generation is increasing, as seen with the decommissioning of the Fort Calhoun nuclear plant. Divesting from generating assets and embracing retail choice could reduce ratepayers' risk by eliminating the potential future costs of stranded assets.
- A more competitive energy landscape would allow consumers to choose among public and private power providers in the state. This arrangement is commonly referred to as "retail choice." In a competitive, retail choice environment, Nebraska public power could pursue a strategy to divest from owning generating assets, and instead, focus solely on the management and operation of transmission and distribution systems. This would incentivize competition to produce from the cheapest sources of generation and substantially reduce the ratepayer risk and uncertainly of owning generation in a changing energy market.

Section 1 - The Southwest Power Pool's Integrated Marketplace Challenges Nebraska's Public Power Model

Introduction

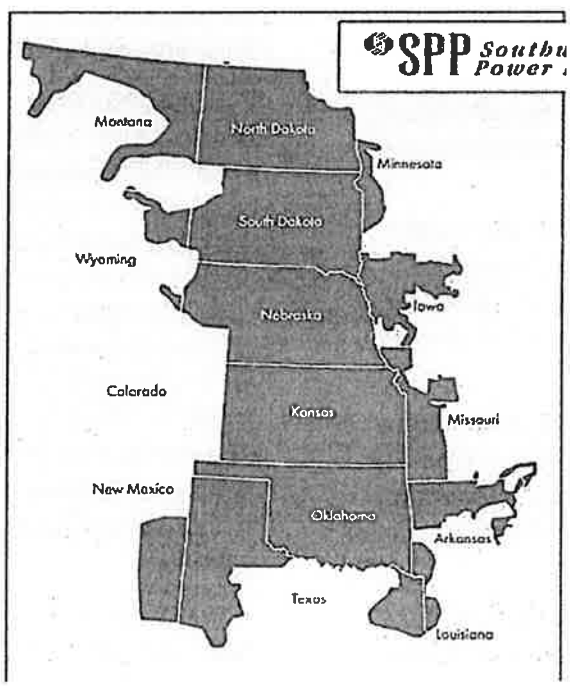
The Southwest Power Pool (SPP) is a regional transmission organization (RTO) based in Little Rock, Arkansas with approximately 600 employees. It covers all or parts of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.

Figure 1.1 shows the SPP footprint. As of June 2016, the SPP had 94 members and 175 market participants (See Appendix A). Several Nebraska Public Power utilities own transmission, including the Nebraska Public Power District (NPPD) and the Omaha Public Power District (OPPD). NPPD and OPPD joined the SPP in 2009.

The SPP footprint recently expanded in October 2015 to include much of North Dakota and South Dakota, and parts of Montana.[2] This expansion added 5,000 megawatts of demand and 9,500 miles of transmission lines. The expansion added more wind production to the SPP footprint and integrated market.

In 2014, the SPP established a pooled marketplace, referred to as the Integrated Market (IM), for buying and selling electricity to its Market Participants (MP). Market Participants in the IM are members of the SPP, which consists of private and public utilities, independent power generators, and retail providers. The purpose of the IM is to optimize generation to meet the demand for the SPP footprint by determining which generation is dispatched for maximum cost-effectiveness.

Figure 1.1: SPP Footprint, 2016



Source: SPP

[2]http://www.spp.org/about-us/newsroom/southwest-power-pool-expands-electric-grid-management-to-14-states/.

When the IM became operational in 2014, the SPP consolidated 16 balancing authority areas into a single balancing authority. This meant that the SPP, instead of the individual SPP members, became responsible for balancing the supply and demand to ensure reliability over the entire SPP footprint. SPP does not own the transmission grid but independently operates it to ensure reliability, and manages long-term planning for future needs. The SPP members continue to own their transmission systems within the SPP footprint.

Essentially, electricity is a commodity that is traded like any other commodity. In the Integrated Marketplace, the SPP acts as the market operator, responsible for clearing transactions. As a market operator, the SPP determines which power is bought and sold based on current demand (load) and supply from electricity generators located throughout the power pool footprint.

The IM has a day-ahead market, where the market price changes hourly, and a real-time market, where the market price changes every 5 minutes. MPs can either submit load and generation into either the day-ahead or real-time market.

A total of 83,465 megawatts (MW) of generation capacity is available from 756 generating plants participating in the SPP integrated market. This currently provides a reserve capacity of 28% to ensure that the SPP can reliably meet demand for electricity during extreme peak times when loads are high.

To put this in perspective, all the current generation in Nebraska could be eliminated and the excess reserve capacity in the SPP integrated market would be enough to supply all customer demand in Nebraska.

The SPP IM does not select generation based on fuel type but on bid price and reliability. The market determines the winners and losers of generation based on the marginal production cost, which does not include any fixed costs.

Since the start of the SPP integrated marketplace, estimated electricity cost savings to MPs have totaled more than $1 billion.[3]

Since the start of the SPP integrated marketplace, estimated electricity cost savings to MPs have totaled more than $1 billion.

How is the SPP market price determined?

In the integrated market, each market participant bids in generation to supply their forecasted load for the following day as required by the SPP. The MP does not have to submit 100% of its forecasted load into the day-ahead market; a portion of the forecasted load can be submitted into the day-ahead market and the remaining portion of the load can be purchased from the real-time market.

Market participants bid generation into the IM based on their marginal cost of production, as allowed by SPP requirements. The generation bid amount does not include any fixed costs. The following terms used for the SPP IM are defined for the purposes of this report:

Generation. Generation is the ability of power plants to generate electricity that is bid into the SPP IM. Generation is also known as capacity, which is the amount of generation that a power plant is capable of producing at a given moment in time. For instance, if a 1,000 MW power plant is sitting idle and is capable of producing 1,000 MW of electricity if called upon (dispatched), then it would have 1,000 MW of capacity that could be bid into the SPP IM. If the same 1,000 MW power plant could only produce 800 MW of electricity, if called upon, due to being derated, then it would only have 800 MW of capacity available to bid into the SPP IM, not 1,000 MW.

There are three types of generation: baseload, intermediate, and renewable. Baseload generation is either fossil fuel or nuclear that are designed to operate at a constant output.

[3]https://www.spp.org/about-us/newsroom/total-savings-from-spp-s-markets-cross-the-1-billion-mark/.

Intermediate generation is designed .o change output more quickly than baseload generation and is used when the demand for electricity changes.

Renewable generation output is based on the conditions (wind and sun) at any given time. Due to variable weather conditions, renewable generation cannot always generate at 100% of its rated output, SPP credits 10% of its rated output for capacity in the SPP IM.

Marginal Cost of Production (or Incremental Energy Cost). This is the incremental cost of a generator to produce electricity. This includes fuel and variable operations and maintenance (O&M) costs. Variable O&M costs are costs for items that are needed to produce electricity, but not needed when the plant is sitting idle. The marginal cost of production changes due to the plant's efficiency at different outputs. The plant does not incur the marginal cost of production when the plant is not producing electricity.

Fixed Cost. This is the generator's cost 'hat does not change based on the output of the generation. This cost would be the same if the plant was sitting idle or operating at 100% of its capacity. Fixed costs include items like labor, debt service, routine maintenance, facilities, and corporate charges.

Cost of Production. This is the total cost of generation, which is sometimes referred to as busbar cost. Cost of production includes both the marginal cost of production and fixed cost.

SPP IM Market Price. This is the price established by SPP based on the generation and load submitted by the SPP Market Participants into the SPP IM. The Market Participants purchase electricity from the SPP IM at their purchase node. For Nebraska public power, the SPP North Hub is used for pricing the electricity that is purchased. Generation that is dispatched by SPP receives the market price for their electricity at the SPP pricing node for the generation's location. Each generation source in the SPP footprint has an SPP pricing node. Since cost data isn't available for Nebraska public)ower generation, the SPP North Hub market pricing will be used in this report.

Generation or Capacity Cost. This is the difference between the cost of production and the SPP market price at the generator's pricing node (Annual Cost of Production - Annual Revenue from the SPP IM). This is the cost to the Market Participant for owning the generation. If the cost of production is more than the SPP market price, the cost must be passed through to the ratepayers in the rates.

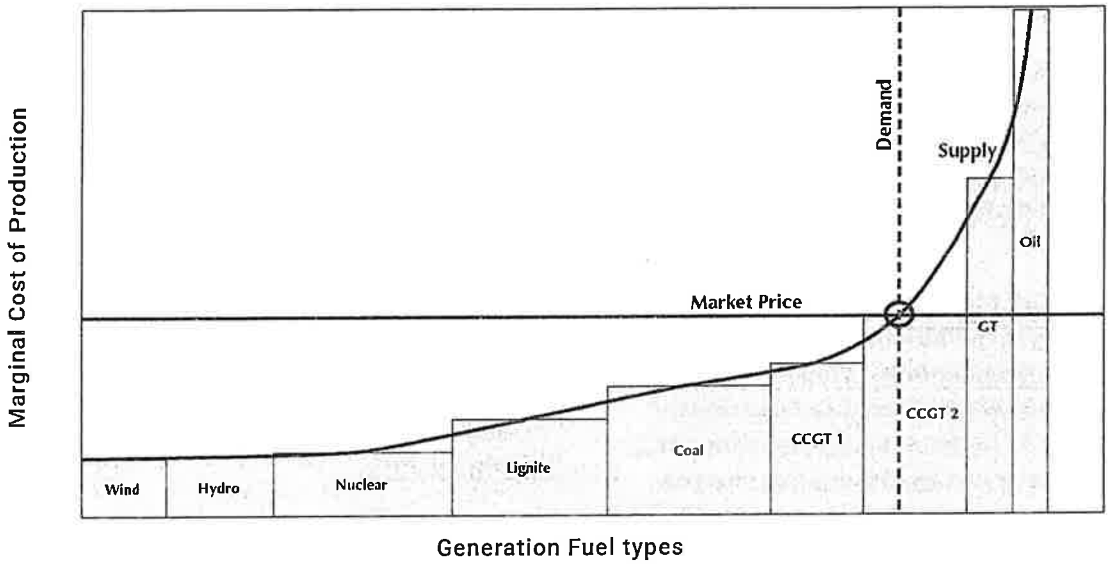
If a power plant that produces 6.8 million megawatt-hour (MWh) of electricity annually with a cost of production of $306 million, and the average annual SPP market price is $20/MWh, the generation cost for that year that must be passed on to the ratepayers is $170 million ($306 million - (6.8 million x $20)).

The SPP combines the forecasted load (demand) of all market participants to determine how much generation is needed to provide the most cost-effective and reliable combination of generation to be dispatched the following day.

For example, Figure 1.2 shows the forecasted load (demand line) and generation (supply curve) intersecting at the CCGT2 generator. The SPP will dispatch CCGT2 and all the generation units left of CCGT2 (i.e. the generators with the lowest marginal cost of production: CCGT1, Coal, Lignite, Nuclear, Hydro, and Wind). In the day-ahead market, the forecast load and generation are bid (offered) in hourly so the dispatch of generation and IM price changes hourly. If an MP's generation isn't selected to be dispatched for any hour in the day-ahead market, the MP can bid their generation into the real-time market using the same bid criteria as the day-ahead market. The MP is not required to submit their total forecasted load in the day-ahead market; load can be purchased from the real-time market at the real-time market price.

The market price in the integrated market is determined by the price of the next available generator that could be dispatched at the forecasted demand (see Figure 1.2). The graph shows the forecasted load (demand) and generation (supply) curve intersect at CCGT 2's marginal cost of production. At this intersection point, the market price is established at the bid price (i.e. marginal cost of production) of CCGT 2. If the market bid price for CCGT 2 was $23.74/MWh, then all

Figure 1.2: How the supply and demand of electricity signals price based on the dispatch order of different generation assets



Source: Goss & Associates

generation bids in the day-ahead market with lower marginal cost of production than CCGT 2 (left of the Demand line) would receive the same market price of $23.74/MWh for that hour.

Since the IM bid (offer) price for generation is based on fuel price, the dispatch order can change depending on fluctuations of fuel prices for different forms of generation. Due to the current generation mix and low gas prices in the SPP footprint, gas-fired generation is on the margin, meaning that gas generators are typically the last generation units dispatched during high demand (on-peak) periods.

During periods of very low demand (off-peak), it is possible that the SPP IM price can go negative because there is more supply than demand. Excess supply is created when large baseload plants (e.g. coal and nuclear) are unable to change output levels fast enough to react to changes in demand. Gas and renewable generators have the ability to rapidly adjust output, making them better able to capitalize on changing market conditions.

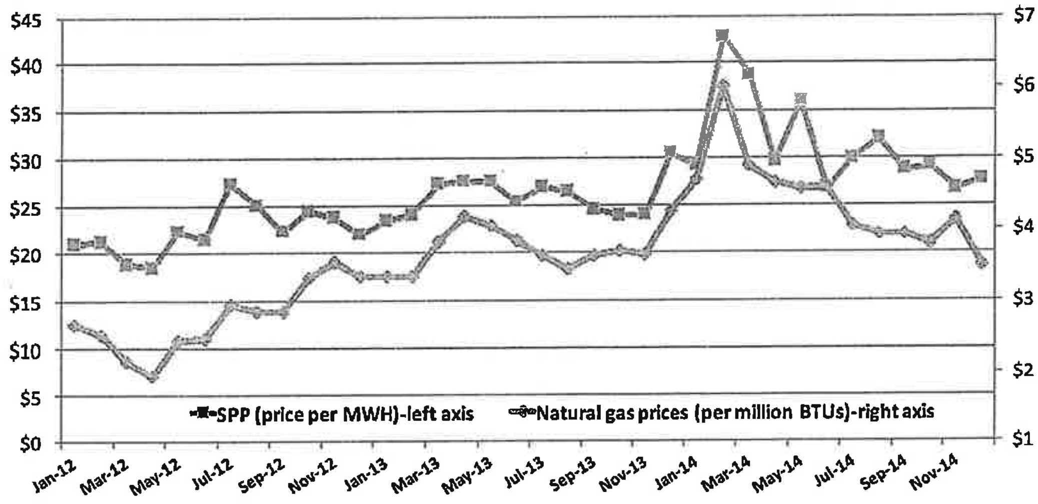
Natural gas prices have trended downward since the second half of 2008. Since electricity produced from gas-fired generators are dispatched as the marginal fuel supply, lower natural gas prices put downward pressure on the wholesale market price in the SPP's IM.

As explained above, it becomes increasingly important to own generation (capacity) with the lowest cost of production, not the lowest marginal cost of production, when participating in the SPP integrated market. The MP's customers must make up the difference between the cost of production and the market price.

Figure 1.3 profiles the relationship between the price of natural gas and SPP wholesale market prices. The data supports a strong positive association between the price of natural gas and SPP market prices. In fact, the correlation coefficient between natural gas prices and SPP market prices from January 2012 to December 2014 was 0.87 indicating that the two move in almost lockstep.[4]

[4]The linear correlation coefficient, measures the strength and the direction of a linear relationship between two variables, in this case natural gas prices and SPP prices. The value ranges between -1.0 and +1.0. A larger the value, the greater the association (e.g. +1.0 indicates two variables move in perfect lock step such as farenheit and centigrade temperature).

Figure 1.3: Natural gas prices and SPP day ahead locational market price, Jan. 2012- Nov. 2014



Source: Goss & Associates, SPP and Federal Reserve of St. Louis

Table 1.1 lists the electricity capacity and consumption by fuel type. As indicated, the consumption and capacity of coal generation has steadily declined, although coal consumption has declined more significantly than the capacity. This indicates that utilities in the region have not altered their generation mix capability as fast as market conditions dictate.

It also supports the hypothesis that electricity producers have reduced utilization (capacity factor) of electricity plants fueled by coal.[5] Likewise, the consumption of natural gas has risen more dramatically than capacity. On the other hand, wind generation has expanded steadily and significantly over that time period.

Table 1.1: SPP capacity (2013-2015) and consumption (2013-2016) by fuel type

Type		2013	2014	2015	2016 (rolling 365)
Coal	Capacity	34.1%	35.4%	33.3%	
Coal	Consumption	61.2%	58.8%	55.1%	47.9%
Natural gas	Capacity	42.0%	46.5%	42.6%	
Natural gas	Consumption	21.2%	18.9%	21.6%	23.4%
Nuclear	Capacity	3.3%	3.4%	3.2%	
Nuclear	Consumption	6.0%	7.9%	8.1%	8.0%
Wind	Capacity	10.0%	11.5%	14.9%	
Wind	Consumption	10.8%	11.8%	13.5%	16.7%
Hydro	Capacity	4.6%	1.1%	4.1%	
Hydro	Consumption	0.6%	2.5%	1.5%	3.7%
Other	Capacity	26.8%	20.8%	23.1%	
Other	Consumption	0.6%	2.5%	1.5%	0.3%

Source: SPP

[5]For example, a 1,000 MW coal plant operating at an 80% capacity factor would produce 7.0 million MWH of electricity in a year (1000*.80*8760). For a 70% capacity factor it would generate 6.1 million MWH of electricity in a year (1000*.70*8760).

There are currently more than 12,000 MW of wind generation in the SPP footprint. The addition of renewable generation and the retirement of coal and nuclear generation has impacted the market price. Since the fuel cost of wind energy is zero, and is dispatched first in the day-ahead market, wind generation lowers the market price by displacing generation with higher fuel cost. The retirement of nuclear generation, however, will increase market prices because nuclear has lower fuel costs than generation currently on the margin (gas-fired). The effect on market prices from the retirement of coal plants depends on whether the fuel cost is above or below the fuel cost on the margin. If it is above the fuel cost on the margin, then it will have no effect on market prices, but if it is below, one can expect the market price to increase.

Since the fuel cost of wind energy is zero, and is dispatched first in the day-ahead market, wind generation lowers the market price by displacing higher fuel-cost generation.

Effect of SPP Integrated Market on Nebraska's Public Power

Prior to the SPP Integrated Market becoming operational in March 2014, Nebraska public power was responsible for dispatching their own generation to match their load. They also acted as the balancing authority for Nebraska.

This meant that nearly all generation from power plants in Nebraska was used to serve the native load in Nebraska. Therefore, the cost of production (fuel, variable operations and maintenance, and fixed) for generation was passed along to customers through rates.

For an illustration of generation costs, see table 1.2. Note: the following information are approximations based on the best information available for various plant types. Nebraska public power has denied a request for information concerning generation costs so actual cost data is not being used.

Table 1.2: Breakdown of generation costs for specific types of power plants

Plant Type	Size (MW)	Marginal Cost of Production ($/MWh)*	Fixed Cost ($/MWh)	Cost of Production ($/MWh)
Large Coal	1,350	13.15	13.20	26.35
Small Coal	225	21.00	33.85	54.85
Nuclear	800	8.90	36.10	45.00
Combined Cycle	250	42.75	117.80	160.55
Wind	300	0.00	20.00**	20.00**

* This would be the generation bid price in the SPP Integrated Market
**This would be the Power Purchase Agreement (PPA) price

The cost for each type of generation ratepayers were paying prior to 2014, when the SPP IM went operational, is as follows:

Table 1.2a: Cost for each type of generation ratepayers were paying prior to 2014, when the SPP IM went operational

Plant Type	Annual Output (MWh)	Cost of Production ($/MWh)	Annual Energy and Demand Cost ($)
Large Coal	9,650,000	26.35	254,277,500
Small Coal	1,120,000	54.85	61,432,000
Nuclear	6,800,000	45.00	306,000,000
Combined Cycle	137,000	160.55	21,995,350
Wind	1,314,000	20.00	26,280,000

Prior to the SPP IM, and based on the costs in table 1.2a above, ratepayers would be charged $669,984,850 for their public power utility to provide them with electricity. If a utility sold 19,021,000 MWh, the generation cost (energy and demand) would have been $35.22/MWh.

After the SPP went operational in 2014, energy and demand costs are separate, as illustrated in Table 1.2b. Note: for simplicity and illustration purposes, the 2015 SPP North Hub average market price is being used; in reality, every generation in SPP has a market price node for their location.

Table 1.2b: Energy and demand costs

	Large Coal	Small Coal	Nuclear	Combined Cycle	Wind
Cost of Production ($/MWh)	$26.35	$54.85	$45.00	$160.55	$20.00
2015 Average Market Price[1] ($/MWh)	$20.28	$20.28	$20.28	$20.28	$20.28
Annual Output (MWh)	9,650,000	1,120,000	6,800,000	137,000	1,314,000
Demand Cost ($/MWh)	$6.07	$34.57	$24.72	$140.27	-$.08
Annual Demand Cost[2]	$58,575,500	$38,718,400	$168,096,000	$19,216,990	-$105,120
Annual Demand Cost[3]	$44,389/MW	$172,082/MW	$210,120/MW	$76,867/MW	-$350.40/MW

[1] Energy Cost
[2] Annual Cost to for generation that must be paid by the ratepayers as a demand cost
[3] Annual Demand Cost ($) divided by Generation Size

The Demand Cost ($/MWh) does not provide much value, the Annual Demand Cost is what is important since this amount must be included in the rates that the ratepayers must pay. The Annual Demand Cost expressed in $/MW is also important for determining the capacity cost relative to other types of generation . As shown in Table 1.2b, nuclear generation is the most expensive generation capacity.

Using the information from the Table 1.2b above, the SPP market price is the energy cost. The capacity or demand cost for the utility's total generation is $284,501,770/year or $14.94/MWh. The total energy and demand cost remains, as before the SPP IM went operational, at $35.22/MWh. As the energy price (SPP market price) decreases the demand cost for generation increases because the difference between the marginal cost of production and the market price isn't high enough to further offset fixed costs. If the generation's cost of production was lower than the market price, the generation would have negative demand cost and would have a positive cash flow.

Since the SPP IM went operational in March 2014, Nebraska public power no longer dispatches their own generation to supply electricity to their customers. Instead, they purchase power from the market, either day-ahead or real-time, which is supplied from generators within the SPP footprint with the lowest marginal cost of production (fuel and variable O&M). See Appendix B for an illustration on how the SPP Integrated Market works for generation and supplying electricity to market participants.

When the SPP market price is lower than Nebraska public power generation's marginal cost of production, the generation assets remain idle and Nebraska's public power utilities purchase electricity from the IM at a cost lower than their generation can produce it because they will not be incurring the marginal cost of production. Purchasing electricity from the SPP IM when the market price is lower than the MP's generators marginal cost of production saves the MP money and should ultimately save the ratepayer money because the MP is purchasing electricity cheaper than the cost of self-dispatching their generation to provide electricity to their customers, which they did prior to the SPP IM.

Table 1.3 shows the average SPP market prices since the IM went operational in March of 2014. As shown, the market price has been lower every year since becoming operational. This is due mostly to the increase of wind generation in the SPP footprint and low natural gas prices.

Table 1.3: Average SPP market price

	Average SPP market price (North hub)
2014 (As of March 1)	$28.06
2015	$20.28
2016 (thru June)	$17.34

Source: SPP

Section 2: Threats facing Nebraska's Public Power Generation

Introduction

The cost effectiveness of Nebraska's public power generation is currently at risk in the SPP IM. There are two main reasons for this: (1) low natural gas prices; and (2) additional wind generation in the SPP footprint.

Low natural gas prices keep the SPP IM market price low. Gas-fired generators are the marginal supply, so bids from those generators typically sets the market price. Lower fuel costs for natural gas generators lead to lower bids in the market since fuel is a major contributor to the generator's bid price.

Low market prices threaten the competitiveness and ultimately the value of coal and nuclear assets owned by Nebraska public power.

The second threat comes from additional wind generation in the SPP footprint.[6] Wind displaces higher cost fossil fuel generation when SPP dispatches generation. Significant increases in wind generation are expected in the SPP footprint.[7] The SPP will have nearly 17,000 MW of installed wind by the end of 2016, up from 12,397 MW in 2015. An additional 2,000 MW is expected to be installed in 2017. As more wind energy is produced, there is risk that Nebraska's coal plants will sit idle more often, less able to recover fixed costs, as electricity is dispatched from wind generation first, and mainly from other states within the SPP footprint.

Excess Coal and Nuclear Generation when Natural Gas is Cheap

Nebraska's generation portfolio has a higher coal and nuclear mix relative to the SPP generation mix. Table 2.1 shows the breakdown of NPPD's and OPPD's generation mix compared to the SPP generation mix. NPPD and OPPD combined have half the wind percentage and nearly 20 percent more coal capacity than the SPP generation mix.

Nebraska's generation portfolio has a higher coal and nuclear mix relative to the SPP generation mix.

Table 2.1: Generation Mix comparison between NPPD and OPPD and the total SPP mix, 2015

	NPPD and OPPD Generation Mix	SPP Generation Mix
Coal	52.2%	33.3%
Natural gas & oil	18.8%	42.6%
Nuclear	19.0%	3.2%
Wind	7.0%	14.9%
Other	3.1%	6.2%
Total	100.0%	100.0%

Source: SPP, NPPD, and OPPD Annual Reports

[6] Wind generation as a percentage of supply in the SPP continues to set records, with penetration now exceeding 40 percent on certain days: http://www.platts.com/latest-news/electric-power/houston/us-southwest-power-pool-sets-new-wind-peak-record-21139345.

[7] The SPP estimates that it can reliably handle up to 60 percent wind penetration: https://www.spp.org/documents/34200/2016%20wind%20integra¬tion%20study%20(wis)%20final.pdf.

Baseload capacity, like coal and nuclear, is expected to continue to decrease in value as wind generation capacity increases in the SPP.[8] For example, in September 2016, NPPD's Sheldon Station went offline because the SPP's wholesale market price was lower than its marginal cost of production. It doesn't make economic sense to burn the fuel to produce electricity which would have been sold below the fuel cost. Fixed costs, however, are still incurred while the plant sits idle.

Baseload capacity like coal and nuclear is expected to continue to decrease in value as wind generating capacity increases in the SPP.

OPPD recently took action to shut down Fort Calhoun Nuclear Station (FCS) because of its high cost of production and low SPP wholesale market prices. In 2015, OPPD's generation capability (capacity) was 3,080 MW and system peak load was 2,315 MW.[9] With SPP requirements to have generation capacity for 112% of peak load, OPPD had 487 MW of excess capacity with FCS. Shutting down FCS will decrease excess generation and reduce generation costs to OPPD ratepayers.

If additional generation is needed due to FCS being shutdown, OPPD can either replace the generation, by building new generation or contracting generation from another supplier, with a lower annual cost of production.

NPPD generates more than four million MWh of excess generation (more electricity is sold to the SPP market than purchased from the SPP market to serve their customers). In 2015, NPPD's generation capability (capacity) was 3,660 MW and system peak load was 2,695 MW.[10] Since SPP requires Market Participants have generation capacity for 112% of their peak load, NPPD had 642 MW of excess capacity. This excess generation would be at produced from NPPD's Cooper Nuclear Station since this is NPPD's generation with the highest annual cost of production.

Even when market prices are above the generation's marginal cost of production, low market prices result in less revenue to help offset the fixed cost of generation. OPPD's decision to shut down the Fort Calhoun station can be seen as an indication of low forecasted market prices in the SPP. OPPD determined that incurring decommissioning costs of over $1 billion today was more cost effective than shortfalls in covering fixed costs while keeping the station operating.[11]

The price of natural gas has reached near record lows in 2016. This has driven SPP IM wholesale market prices below $20/MWh for several months this year. Figure 2.1 shows this year's monthly gas price (right axis) compared to the average monthly wholesale market prices (left axis) in the SPP IM.

The price of natural gas has reached near record lows in 2016. This has driven SPP IM wholesale market prices below $20/MWh for several months

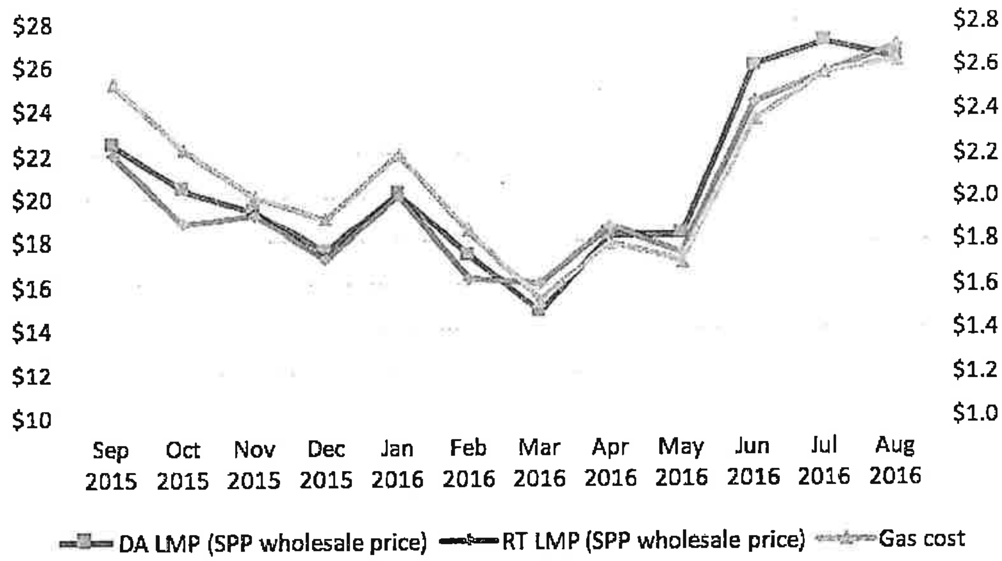
[8] Energy Information Administration (EIA), 'Higher wind generation in the Southwest Power Pool is reducing use of baseload capacity', http://www.eia.gov/today-inenergy/detail.php?id=12831.

[9] OPPD quick facts: http://www.oppd.com/media/216550/quick-facts.pdf.

[10] NPPD Financial and Sustainability Report, 2015 (http://www.nppd.com/assets/publications/2015FinancialSustainabilityReport/files/assets/basic-html/page-1.html#).

[11] http://www.oppd.com/news-resources/news-releases/2016/june/oppd-board-votes-to-decommission-fort-calhoun-station/.

Figure 2.1: SPP IM wholesale market prices versus the cost of natural gas



Source: SPP State of the Market Report, Summer 2016

The future price of natural gas is uncertain, but projections of supply growth versus demand growth in the United States indicate that excess supply from shale will remain. Projections by the U.S. Energy Information Administration (EIA) indicate that by 2020 domestic supply will substantially outpace domestic consumption, making the U.S. a net exporter.[12] Expect excess domestic supply to put downward pressure on the price of natural gas.

Although U.S. energy policy is uncertain going forward, the potential implementations of regulations from the Clean Power Plan could continue to increase the cost of production of fossil fuel generation. With Nebraska's heavy reliance on coal, there is a presence of regulatory risk.

Renewables Displace Baseload Generation

The growth in low-cost wind generation in the SPP footprint is putting downward pressure on the SPP IM wholesale market prices. As the amount of wind generation increases throughout the SPP footprint, expect this low-cost source of generation to drive down average wholesale market prices in the SPP IM as it displaces fossil-fueled baseload generation.

In October 2015, the SPP expanded its footprint to cover most of North Dakota and South Dakota, and parts of Montana. This added a substantial amount of wind generation to the SPP, raising wind generation as a percentage of total generation resources. As a result, more wind is now available to dispatch prior to other sources of generation.

In addition, wind generation in the SPP footprint is currently growing and is expected to continue to grow because of the recently renewed federal renewable electricity production tax credits (PTC). The PTC is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources. The electricity must be sold by the producer to an unrelated person or organization. Originally the duration of the credit was 10 years for all facilities placed into service after August 8, 2005.

In December 2015, Congress passed the Consolidated Appropriations Act, which extended the expiration date for this tax credit to December 31, 2019, for wind facilities commencing construction. For 2016, the inflation adjustment factor used by the IRS is 1.556, resulting in a 2016 calendar year tax credit amount of $0.023/kWh. The tax credits do, however, phase down with projects commencing construction after December 31, 2016.

[12]http://www.eia.gov/pressroom/presentations/sieminski_06282016.pdf..

The tax credit phase-down for wind facilities is a percentage reduction in the tax credit amount listed above: (a) for wind facilities commencing construction in 2017, the PTC amount is reduced by 20 percent, (b) for wind facilities commencing construction in 2018, the PTC amount is reduced by 40 percent, and (c) for wind facilities commencing construction in 2019, the PTC amount is reduced by 60 percent. The duration of the credit is 10 years after the date the facility is placed in service.[13]

These recently renewed tax credits are incentivizing wind generation investment throughout the SPP, putting downward pressure on the IM wholesale price. Nebraska's public utilities do not pay taxes and therefore are unable to directly benefit from tax credits. However, in most cases, wind generation is purchased from a private wind developer through a Power Purchase Agreement (PPA).

These recently renewed tax credits are incentivizing wind generation investment throughout the SPP, putting downward pressure on the IM wholesale price.

Nebraska's public power benefit from federal tax credits indirectly because they are factored into the PPA price along with any other capital or fixed costs incurred by wind generators. The PPA price for electricity can be thought of as the cost of production when comparing to other types of generation.

Since the private wind developer can receive tax credits, the price of PPAs incorporate those cost savings, allowing Nebraska Public Power to indirectly benefit from overall cheaper wholesale prices of electricity.

PPAs to purchase wind energy are currently averaging $20/MWh in the interior states, according to recent analysis by the Berkeley Lab and the U.S. Department of Energy.[14] PPAs at this price are significantly less than NPPD's and OPPD's average generation cost of production, and below the average 2015 SPP IM wholesale market price.

The growth of wind generation throughout the SPP will displace baseload generation in the dispatch order, raising the risk that baseload plants sit idle more often. This will raise the overall costs to own those types of plants, since revenue will not be generated to help offset fixed costs. This increases the risk that costlier generating assets will be forced to close as demand for baseload will not keep pace with this additional generation capacity.

The growth of wind generation throughout the SPP will displace baseload generation in the dispatch order, raising the risk that baseload plants sit idle more often.

[13] Renewable energy facilities placed in service after 2008 and commencing construction prior to 2015 (or 2020 for wind facilities) may elect to make an irrevocable election to claim the Investment Tax Credit (ITC) in lieu of the PTC. Wind facilities making such an election with have the ITC amount reduced by the same phase-down specified above for facilities commencing construction in 2017.

[14] PPAs for wind in the interior states have a significant cost advantage to the rest of the nation. In 2013, wind PPAs signed in the interior states averaged between $20-$25, whereas the Great Lakes region averaged above $40 and the West and Northeast region averaged above $50: http://energy.gov/sites/prod/files/2016/08/f33/2015-Wind-Technologies-Market-Report-Presentation.pdf.

Since wind generation is intermittent, it only receives capacity in the SPP integrated market for only 10 percent of its nameplate capacity (i.e. 10 MW for a 100 MW wind farm). This is unlike other types of generation, which receive credit for the full amount of nameplate capacity. Wind generation is bid into the SPP IM the same as other generation, but the credit counted toward market capacity requirements is different.

This is done to ensure that there is enough generation available when the wind does blow. Expect the SPP to consider larger capacity credit for wind in the future as energy storage technologies advance to alleviate intermittency concerns.[15] This will further decrease the value of baseload generation.

It is true that Federal Tax Credits are a key driver of the expected growth in wind generation throughout the SPP footprint. After the tax credits expire, expect investment in wind to lessen. However, cost of wind generation is falling rapidly and is expected to become competitive, even without tax credits, relative to new builds of other forms of energy.[16]

If new generation (capacity) is needed to supply demand growth in the future, expect wind and solar to compete with new builds of coal, natural gas, and nuclear.[17] The cost of solar has fallen rapidly in recent years due to increases in investment worldwide.[18]

15 Although unproven in the market, industrial-sized batteries have seen some traction at the utility level. Tesla recently signed a deal to supply a California utility with industrial capacity lithium batteries to reduce intermittency concerns from renewables: http://www.bloomberg.com/news/articles/2016-09-15/tesla-wins-utility-contract-to-supply-grid-scale-battery-storage-after-porter-ranch-gas-leak.

16 Lazard estimated that the unsubsidized levelized cost of energy for wind has decreased 61 percent from 2009 to 2015. The unsubsidized levelized cost of energy for solar has decreased 82 percent during that same period. New wind builds, unsubsidized, now average between $32-$52/MWh, compared to new coal at $61-$150/MWh and new natural gas at $52-$78/MWh.

17 The EIA projects that in 2022 the LCOE for wind and solar will be $64.50/MWh and $84.70/MWh, respectively, compared new builds of coal to be $139.50/MWh and nuclear to be $102.80/MWh. New builds of natural gas LCOE is expected to range from $57-$84/MWh: https://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf

18 The learning curve (i.e. production cost decrease) for solar follows a trend called Swanson's Law. Swanson's Law is the observation that the cost of solar decreases 20 percent every time the cumulative shipped volume of photovoltaics doubles. Worldwide shipments of photovoltaics are growing fast, led by investment in Asia, with a compounded annual growth rate of 42 percent from 2000-2015: https://www.ise.fraunhofer.de/de/downloads/pdf-files/aktuelles/photovoltaics-report-in-englischer-sprache.pdf.

Section 3: A Case for Retail Choice in Nebraska: The effect on electric rates, reducing ratepayer risk, and the need for greater transparency using unbundled billing

A Case for Unbundling and Retail Choice in Nebraska

Nebraska public power has changed significantly since 1936 when public power was established to provide power to rural customers in Nebraska. More changes came when Nebraska public power joined the Southwest Power Pool in 2009 and began participating in the SPP Integrated Market in 2014, where they now buy and sell wholesale electricity.

Today with competitive wholesale energy markets, electricity is no longer a natural monopoly. Transmission and distribution systems, however, do remain for the most part natural monopolies because it is typically not economical to duplicate transmission and distributions systems in a given area. Providing electricity and being a transmission owner are two completely different business models, and as such it makes no sense for them to be bundled together.

Participating in a competitive wholesale market involves much risk and uncertainty, whereas being a transmission owner involves little risk (mainly weather events) since the same amount of electricity is transported through the transmission system regardless of who is providing the electricity. This is also holds true for the distribution system. The transmission and distribution system owner has the responsibility for maintaining their system to deliver electricity from the wholesale market to the end-use (retail) customer.

In 2009, when Nebraska public power joined the SPP, Nebraska was no longer an electricity island, but part of a much larger market-based RTO. The landscape changed even more dramatically in 2014 when the SPP IM became operational. In this environment, Nebraska public power no longer dispatches power plants or supplies electricity to their customers with their own generation. These functions were all turned over and are now the responsibility of the SPP.

As part of being members of the SPP, Nebraska public power no longer maintains the reliability of the transmission system in the state. Transmission owned by Nebraska public power is regulated by the Federal Energy Regulatory Commission (FERC). In 1996, FERC issued Order 888 to provide "open access" to transmission at non-discriminatory rates to third-party electricity providers to allow for a competitive wholesale electricity market.

What this means is that private electricity generators (e.g. wind farms) or power marketers are able to use transmission infrastructure owned by Nebraska public power for a regulated, set rate, which is non-discriminatory. This open-access infrastructure makes retail choice possible, where private power marketers with access to competitive generation and/or lower overhead costs can participate in the electricity market and potentially provide more competitive options to ratepayers in the state.

Furthermore, according to Nebraska legislative research, three conditions must be met for customer (retail) choice to be effective and beneficial to the citizens of Nebraska.[19] They are:

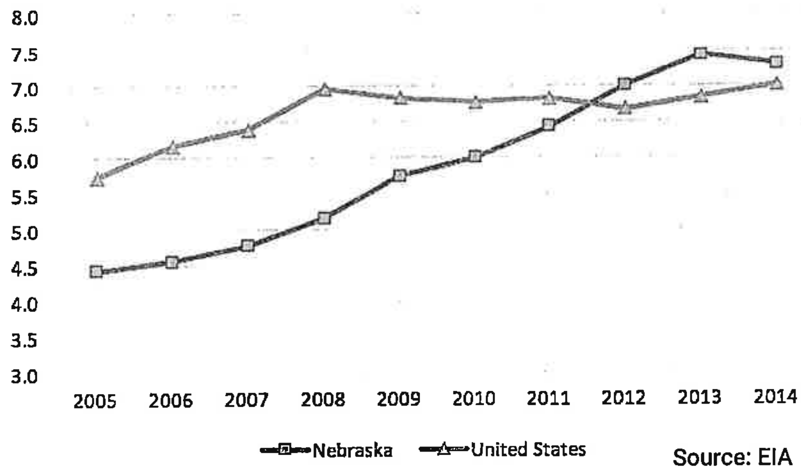
- A viable regional transmission organization and adequate transmission must exist in Nebraska or a region that includes Nebraska;
- A viable wholesale electricity market must exist in a region that includes Nebraska;
- Wholesale electricity prices in the region must be comparable or competitive to Nebraska prices.

[19]Annual report – Monitoring of "Conditions Certain" Issues 2010 Report in Neb. Rev. Stat. 70-1002 (6) to (8), dated 2010.

The report at the time stated that the first two conditions were satisfied and the last condition was not satisfied. However, since the report was last issued in 2010, Nebraska public power has significantly raised rates across the board and wholesale market prices have dropped significantly.

Figure 3.1 shows industrial rates in Nebraska compared to the United States from 2005 to 2014. Compared to US averages, the industrial rate in Nebraska became more expensive in 2012. Comparing Nebraska's rates to the U.S. understates how uncompetitive the state is to the surrounding region, as electricity rates on the East and West coast are usually significantly higher than the Midwest. Having uncompetitive industrial rates is a deterrent for bringing and keeping companies in Nebraska.

Figure 3.1: Nebraska's average industrial rate (cents per kWh) per year compared to the U.S. 2005-2014



Source: EIA

Wholesale market prices in the SPP IM are currently more competitive as well. Based on figures reported in NPPD's and OPPD's annual report, SPP IM wholesale market prices are substantially below the cost of production for NPPD's and OPPD's generation. As shown in Table 3.1, in 2015, NPPD had an average generation cost of production of \$28.21/MWh and OPPD had an average generation cost of \$32.11/MWh.[20] The 2015 average SPP IM day-ahead market price was \$22.84/MWh and the real-time market price was \$21.68/MWh.[21] The 2015 SPP average IM prices include both the North and South Hub. NPPD and OPPD had generation cost of production that were 23.5 percent and 40.6 percent, respectively, higher than the SPP IM day-ahead market price. Both the recent rise in rates for consumers and the decreasing market price of wholesale electricity satisfy the third criteria listed above. Retail choice in Nebraska would be effective and beneficial according to the guidelines of the legislative report discussed above.

As outlined in Section 2, lower wholesale market prices are the result of low natural gas prices and more renewable sources of generation in the SPP footprint. Natural gas prices in 2017 are expected to remain lower than the average price of the last five years.[22] Renewable generation is expected to expand significantly within the SPP footprint over the next few years due to the five-year extension of production tax credits. Expect wholesale market prices to remain low as the renewable market matures and natural gas extraction continues to provide plentiful supply.

This environment has resulted in wholesale market prices in the SPP IM dropping below the cost of production of coal and nuclear generation, creating additional losses for those types of plants.

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[20] Reported average NPPD and OPPD generation costs presented here due not include capital costs or debt servicing costs, therefore these figures underestimate the true cost of generation, but still provide a conservative comparison for competitiveness to market prices.

[21] These prices were averaged from the SPP North and South Hubs. Source: SPP State of the Market Report, Winter 2016; https://www.spp.org/documents/37619/qsom_2016winter.pdf.

[22] https://www.eia.gov/forecasts/steo/report/natgas.cfm.

Table 3.1: Comparison of NPPD and OPPD average generation costs versus the SPP 2015 integrated market average prices

NPPD average generation cost	$28.21
OPPD average generation cost	$32.11
SPP IM day-ahead average price	$22.84
SPP IM real-time average price	$21.68

Source: SPP, OPPD and NPPD annual reports

The decision to decommission OPPD's Fort Calhoun nuclear plant depended partially on the expectation that wholesale market prices in the SPP IM would remain low, making the plant expensive to operate relative to other generation resources. This controversial decision is a signal that OPPD's leadership does not expect wholesale market prices to return to levels where this nuclear station would be cost effective.

The financial risk to ratepayers in owning generation is increasing, as seen with the shutdown and decommissioning of the Fort Calhoun plant. Divesting from generating assets and embracing retail choice could reduce ratepayers' risk by eliminating the potential future costs of stranded assets. In this case, stranded assets are generating assets such as coal or nuclear plants that decrease in production value due to a change in the economics of the industry.

Stranded assets are generating assets such as coal or nuclear plants that decrease in production value due to a change in the economics of the industry.

Currently, inexpensive renewable generation, greater environmental regulations, and an excess supply of natural gas threaten the competitiveness of Nebraska's coal and nuclear plants, raising the risk that more plants will become more uneconomical in the future.

A more competitive energy landscape would allow consumers to choose among public and private power providers in the state.

This arrangement is commonly referred to as "retail choice." In a competitive, retail choice environment, Nebraska public power could pursue a strategy of competing in the energy market or divest from owning generating assets, and instead, focus solely on the management and operation of transmission and distribution systems.

Retail choice would incentivize competition by owning generation with the lowest production costs and maintaining low corporate overhead costs. This would substantially reduce the risk and uncertainly to the ratepayer in a changing energy market.

NPPD Wholesale Power Contact Renewal

In 2015, many rural public power districts and municipalities approved a new 20-year NPPD 2016 Wholesale Power Agreement.[23] This agreement requires that those who approved the contract to purchase the majority of their wholesale power requirement from NPPD who buys the power from the SPP IM. The agreement does not specify any price for the electricity but only a performance criteria that allows the customer to decrease the required amount of electricity that is purchased from NPPD if NPPD's rates go up drastically.

Several of NPPD's current wholesale customers did not sign the NPPD 2016 Wholesale Power Agreement, and decided instead to contract with other wholesale power providers.[24] This is possible due to the competitive wholesale markets and open access to transmission.

[23]NPPD 2016 wholesale power contract (http://info.cityoflex.com/ccdocs/meeting/2015/October27/5C102715.pdf).

[24]http://www.omaha.com/news/nebraska/rising-rate-hikes-prompt-some-nppd-customers-to-look-to/article_d99e15f9-e41d-58dc-8c3d-ac03c7cc36ec.html.

The Cost Composition of Electricity Rates

To understand how divesting from generation and embracing retail choice in Nebraska would affect ratepayers, it is important to know the composition of electric rates and how each cost component would be affected.

Electric rates are made up of various components that recover the electricity provider's costs to deliver their product to the customer. The two major types of electric rates are wholesale and retail.

Wholesale Rate: Wholesale power is the bulk electricity that is delivered by a wholesale power provider to the retail electricity providers for resale to its customers. Bulk electricity is bought and sold into an energy market similar to other commodity markets. The major cost components that go into a wholesale rate are: energy cost, demand cost, transmission cost and the wholesale power provider's overhead. For NPPD in 2014, the breakdown for wholesale energy costs is; 47% Energy, 39% Demand, 10% Transmission, and 4% other.

Retail Rate: The retail rate is what the end-use customer pays for electricity. There are typically three categories of retail rates that are based on electricity usage: industrial, commercial, and residential. Wholesale power is delivered to the retail customer by the local distribution entity after adding on the distribution charge. Local entities are often rural electric associations (REAs) or cities. The end rate paid by the retail customer is the retail rate. The retail rate includes the wholesale power cost and distribution cost to the customer. The breakdown of the cost components of the retail rate is generally: 60% wholesale electricity cost, 10% transmission, and 30% distribution.

Electricity Cost: This is the cost the wholesale power provider pays to purchase the electricity from the energy market. The energy market updates the electricity price every hour in the day-ahead market and every five minutes in the real-time market. The average 2015 market price for Nebraska public power was $20.28.

Transmission Cost: This is the cost the wholesale power provider pays to get the electricity from the energy market to the wholesale customer. Wholesale power is transported through transmission lines. The wholesale power provider may or may not own the transmission lines. The cost to use the transmission system is the same for all wholesale power providers that uses the transmission system.

Distribution Cost: This is the cost the local energy provider, usually a rural power district or city, pays to get the wholesale electricity from the transmission system to the retail customer.

Overhead: This is the cost that determines if the wholesale power provider's rate is competitive, because the costs for electricity and transmission are essentially the same for all wholesale power providers. Overhead costs include demand, debt service, administration, employee healthcare and pension plans.

One other major component of overhead is demand (capacity) costs. As mentioned above, capacity is the ability to generate electricity that can be supplied to the energy market at any given time when called upon to meet the market demand for electricity. The wholesale power provider must either own or purchase capacity to meet the energy market requirements for capacity (i.e. if a wholesale power provider is going to purchase 100 MW of electricity, then it must have at least 100 MW plus required SPP margin of capacity available).

It should be noted that just because a MP has 100 MW of capacity available, generation from another market participant might be used to produce the electricity needed to supply the MP's 100 MW load.

Generation or capacity cost is comprised of the total expenses (fuel, operation & maintenance, facilities, capital improvement, etc.) minus the revenue from selling the electricity generated to the energy market, such as an SPP integrated market. Capacity costs vary significantly depending on the type of generation (i.e. coal, nuclear, gas, renewable, hydro).

The Importance of Cost-Based Rates

The electricity rates on a ratepayer's most recent bill might not represent the true cost of power. It is possible that a utility could defer costs (i.e. pensions, retirement, decommissioning, debt, etc.) into the future in order to avoid raising rates in the present. These deferred costs, also known as unfunded liabilities, could expose customers to unexpected higher rates in the future.

An unfunded liability exists when a utility incurs an expense but defers payment. If current rates are based on deferred expense, the rate doesn't represent the true cost of electricity today. Therefore, once those unfunded liabilities come due, future customers will face higher rates, while customers today obtain the benefit.

An unfunded liability exists when a utility incurs an expense but defers payment. If current rates are based on deferred expense, the rate doesn't represent the true cost of electricity today.

When the ratepayer is locked into a monopolistic power provider and cannot choose from whom they purchase electricity, the rate should be cost-based to avoid receiving benefit from services they are not paying for. As described above, deferred costs by an electricity provider (public or private) are unacceptable for cost-based rates. If an electricity provider (public or private) makes bad business decisions, future ratepayers suffer the outcome because there is no other option for the customer to choose. The utility suffers no consequences in the form of lost customers as the result of its decisions.

Providing Cost Transparency through Unbundled Billing

With several cost components making up an electric rate, it is important that consumers understand what is driving any changes in their rates. Consumers can gain insight into costs of electricity production through unbundled billing.

Unbundled billing improves transparency and accountability by separating the cost components of the rate that the electric utilities charge. An example of an unbundled bill is illustrated in Appendix C, Example of an Unbundled Bill.

For example, an unbundled bill would show separate charges for energy, demand, transmission, and distribution, supplemental charges, which all contribute to the overall rate. Additional charges such as decommissioning costs and metering charges should also be included in a properly unbundled bill. This line-by-line billing information allows the ratepayer to scrutinize each component. When rates increase, an unbundled bill would indicate the factors that caused it.

Unbundled bills should be a staple in public power districts and cities in Nebraska. As a public power state, Nebraska's ratepayers vote for the board of directors of the public utilities that represent and serve them. A voter should be informed by seeing which costs drive any rate changes. Without this level of transparency, ratepayers lack the knowledge to make informed decisions when electing the board of directors who have the fiduciary responsibility to hold management accountable for decisions it has made.

The National Energy Marketers Association (NEM) says that "proper rate unbundling is a prerequisite to sending proper price signals, to assist in making educated consumption decisions, and to permit suppliers to invest risk capital to make competitive product and service offerings available to consumers."[25]

Increased transparency from unbundled billing is also important in today's changing energy landscape because of competition from renewable sources of generation. The preference for renewables is often overshadowed by the assumed higher costs rather than recent objective data. Unbundled bills would give Nebraska ratepayers insight into whether renewable sources of generation are cost effective compared to current sources such as coal and nuclear. Alternative sources of generation, such as wind or solar, could be offered by companies competing in a retail choice environment.

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[25]https://www.energymarketers.com/Documents/nem_me_unbundling_ nal_cmts.pdf.

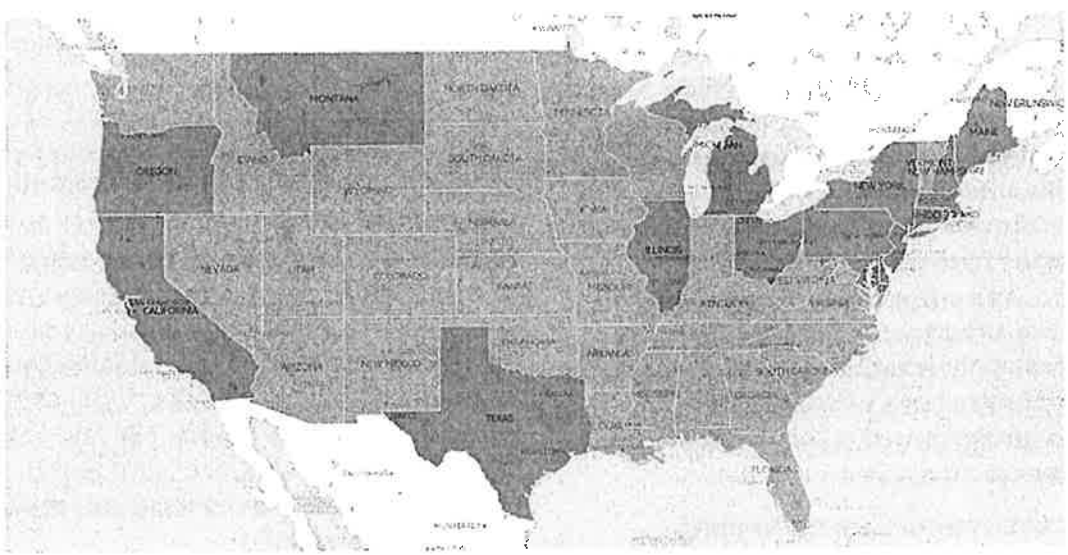
Having the costs separated, particularly distribution and transmission, would allow consumers to clearly compare prices of different energy providers. There is nothing physically (transmission or distribution) to prevent retail choice from being implemented in Nebraska. With retail choice, the only thing that would need to change would be a line item on the bill to show who the customer is purchasing electricity from. The transmission and distribution cost would remain the same as it is currently, with local entities delivering the electricity to the consumer. SPP is responsible for the planning and reliability of the transmission system. All repairs would still be handled the same as they are today, by the local distribution or transmission system owners.

Electricity is the competitive component of a customer's bill, whereas other charges are non-competitive; all retailers rely on the same transmission and distribution systems and incur the same charges. In a retail choice environment, electricity providers compete on how efficiently they can supply a commodity: electricity. Unbundled bills give clear information on who supplies electricity in the most cost-effective manner.

Retail Choice in Practice

Seventeen states have adopted retail choice. The level of adoption differs, with some states allowing full retail choice for all customers, and others providing it only to commercial and industrial customers. Retail choice becomes more important as competing sources of electricity production enter the market. Without retail choice, consumers are left with no other option than one with expensive rates if the monopoly utility makes poor business decisions such as choosing the wrong portfolio of generating assets. Figure 3.2 shows states that have implemented some form of retail choice.

Figure 3.2: States that have implemented retail choice



Source: EIA

Retail choice in Texas is administered by the Public Utility Commission through the website powertochoose.org (see Appendix D). This site provides a good example of how retail choice could work for residential, commercial, and industrial ratepayers in Nebraska. After entering a zip code, the ratepayer is shown multiple competitive offers from different electricity retail providers available in their area. Offers mainly differ in terms of price and contract length.

Some contracts last only three months while others last an entire year. This gives the ratepayer the option to lock in a current rate for an extended time, if that rate predictability is well-suited to their budget. Some retail providers offer rates based on the source of generation. This gives the ratepayer the option to buy electricity from a retailer that sources electricity entirely from renewables, if that's preferred.

Some retail providers offer rates based on the source of generation. This gives the ratepayer the option to buy electricity from a retailer that sources electricity entirely from renewables, if that's preferred.

Electric retailers offer different rates because each company has its own strategy when it comes to sourcing the most cost effective sources of generation. Generation costs are based on many variables, most prominently fuel costs and technological advances. Since those variables are unknown in the future, strategic decisions should be made in an environment where market forces dictate the allocation of capital, which is not possible in a monopoly environment. The invested capital financed by ratepayers is at risk with publicly-owned generation, whereas, in retail choice, private investors bear the investment risk.

A retail choice environment promotes competition among suppliers and matches preferences to consumers. This ensures that the most cost-effective strategy to procure generation is available, which is passed on to consumers through lower rates. Ineffective generation investment strategies will be uncompetitive, ceasing to exist. On the demand side, consumer choice is especially important in being able to match production to consumer preferences, especially in regards to environmental concerns.

A retail choice environment promotes competition among suppliers and matches preferences to consumers.

If consumers prefer renewable sources of generation, a retail choice environment would be able to match that preference effectively. A competitive environment increases both productive and allocative efficiencies.[26]

Potential Cost Savings from Retail Choice

The price of a retail rate is comprised of approximately 60 percent generation cost, 30 percent distribution cost, and 10 percent transmission cost. The ability of retail choice to offer competitive rates is dependent on the costs of each retailer's owned generation mix and/or costs of wholesale purchases. The conditions that can affect wholesale energy costs can change rapidly, and are variable throughout the state. For example, the current market price for wholesale energy supplied through wind PPAs has recently dropped to levels that are very competitive to other sources of generation. Compared to the costs of owning and operating coal and nuclear plants, a retailer that is able to quickly adapt and execute wholesale purchases in favorable market conditions would be in a more competitive position. The combination of low-priced wholesale electric purchases and less overhead expense, should allow providers to put competitive downward pressure on rates in a retail choice environment.

To illustrate the variability in retail rates throughout the state, see Appendices E and F.

[26] Productive efficiency is the ability to produce at the lowest cost. Allocative efficiency is the ability to match production with consumer preferences. Market failures occur when the economy fails to allocate resources efficiently.

In the competitive wholesale environment, power districts, cities, and regional utilities are able to seek out the lowest cost wholesale supply, as did twelve cities and a regional utility in Nebraska.[27] For example, instead of NPPD, South Sioux City has signed a wholesale provider contract with a utility in Ohio and Northeast Nebraska Public Power District has signed with a provider in Kentucky.

This is because approximately 60 percent of the retail rate a city or regional utility offers to consumers is made up of the wholesale cost of electricity, so the cheaper they can procure this electricity supply, the more cost savings they can pass on to consumers.

In contracting with cheaper wholesale providers, entities like Northeast Nebraska Public Power and South Sioux City have less costs incurred with this wholesale supply component of the rate, which can then get passed on to end users in the form of cheaper rates.

This explains some of the rate variability possible throughout the state. Similar competitive forces, as seen in the wholesale competitive market, could lead to additional downward pressure on rates if applied to the retail environment.

According to the EIA, in 2015 Nebraska ratepayers paid more than $2.5 billion for electricity.[28] The ratepayer could save between $250-$400 million annually if retail choice was permitted in Nebraska as demonstrated by the public power districts and cities that chose to purchase their power from utilities outside of the Nebraska Public Power System. Since the SPP IM went operational, the competitive market price for electricity has dropped 38% but Nebraska public power electric rates have not decreased. In fact, many ratepayers are having to pay more for electricity because NPPD and OPPD are increasing the customer charges due to sustained revenue shortfall from external market factors and lower customer usage.

The Nebraska Public Power Model currently is not effective in the SPP wholesale power market due to past and current decisions to build and maintain generation resources. With a wholesale power market in place, the Nebraska Public Power Model should be changed to allow free market principles to work to lower electricity prices for the ratepayer. This would be consistent with the findings of the legislative study for retail choice in Nebraska.

27http://www.omaha.com/news/nebraska/cities-regional-utility-turn-down-new-nppd-contracts/article_205502e9-d68b-5cf5-8c5c-23eecf9aa5ec.html.

28http://www.eia.gov/electricity/sales_revenue_price/

Appendix A: SPP market participants

(source: https://www.spp.org/about-us/footprint/)

Alliant Energy Corporate Services, Inc.
American Electric Power West
Appian Way Energy Partners Southwest, LLC
APX
Arkansas Electric Cooperative
Associated Electric Cooperative, Inc. – Power Market
ATNV Energy, LP
Automated Algorithums
Basin Electric Power Cooperative
BioUrja Power, LLC
BJ Energy
Black Hills Power
Black Oak Energy LLC
Blackout Power Trading
Blue Canyon Windpower
Boston Energy Trading & Marketing
BP Energy Company
Brookfield Energy Marketing LP
Brookfield Renewable Energy Group
BTG Pactual Commodities (US)
Buffalo Dunes Wind Project
Calicot Energy
Calpine Energy Services
Canadian Woods Products
Caney River
Canopus Power Trading, LLC
Cargill Power Markets
Carpe Diem Trading II
Castleton Power Trading, LLC
Chisholm View Wind Project
Cimarron Wind Energy
Citigroup Energy
City of Chanute
City of Fremont
City of Grand Island
City of Independence, Mo.
Conoco Phillips
CP Bloom Wind
Cumulus Master Fund
Darby Energy
DC Energy Midwest
DC Transco, LLC
Dempsey Ridge Wind Farm
Denver Energy
Dogwood Power Management
DTE Energy Trading
Dufossat Capital VI
Dynasty Power
East Texas Electric Coop
Ecesis
EDF Trading North America
EDP Renewable North America
eKapital Investments
Emera Energy Services
Empire District Electric
Endurance Energy Midwest LLC
ETC Endure Energy
Flat Ridge 2 Wind Energy
Franklin Power
Freepoint Commodities, LLC
Galt Power
Golden Spread Electric Cooperative
Goodwell Wind Project
Google Energy
Grand River Dam Authority
GRG Energy
Guzman Energy
H.Q. Energy Services US
Harlan Municipal Utilities
Hastings Utilities
Heartland Consumers Power District
Hexis Energy Trading
High Majestic Wind II
Iberdola Renewables
Inertia Power III
Intergrid Midwest Group
Invenergy Energy Management
J. Aron and Company
Kansas City Board of Public Utilities
Kansas City Power and Light
Kansas Municipal Energy Agency
Kansas Power Pool
Kentucky Municipal Power Agency
Lincoln Electric System
Little Elk Wind Project
LM Power
Macquarie Energy
MAG Energy Solutions
Marshall Wind Energy
Mercuria Energy America
Merrill Lynch Commodities
MET Southwest Trading
MidAmerican Energy Company
Midwest Energy
Midwest Energy Trading East
Minco Wind
Minnesota Muncipal Power Agency
Minnkota Power Cooperative, Inc.
Missouri Joint Municipal
Missouri River Energy Services
Montana-Dakota Utilities
Monterey SW
Monterey SWF
Morgan Stanley Capital Group
Morningstar Commodity Data, Inc
Municipal Energy Agency of Nebraska
NextEra Energy Power Marketing
NJ Resources
Noble Americas Gas & Power
Noble Great Plains Windpark
Northern States Power
Northpoint Energy Solutions
Northstar Trading LTD
NorthWestern Corporation dba NorthWestern Energy
NSP Energy Trading
Occidental Power Services
Oklahoma Gas & Electric Company
Oklahoma Municipal Power Authority
Omaha Public Power District
Oneta Power
Otter Tail Power Company
Peninsula Power, LLC
Pharetram Energy Services, Ltd.
Powerex Corp.
Public Service Co. of Colorado
Public Service Co. of Colorado MISO MP
Pure Energy
Rainbow Energy Marketing
Resale Power Group of IOWA
RPM Access LLC
Saracen Energy Midwest
Seiling Wind LLC
Sempra Generation
SESCO SPP Trading LLC
Shell Energy North America
Smoky Hills Wind Project II
Solea Energy, LLC
Southern Company Services
Southwestern Public Service
Sunflower Electric Power
Sustaining Power Solutions
SW Power Trading, LLC
TEC Energy, Inc.
Tenaska Power Services
Tennessee Valley Authority
The Energy Authority
Tios Capital, LLC
TPS1
TPS2
TPS3
TPS4
TPS5
TPS6
TPS7
TPS8
Trailstone Power
TransAlta Energy Marketing (U.S.) Inc.
Trumpet Trading LLC
Tungsten Power LP
Twin Eagle Resource Management
Uncia Energy LP - Series D
Utilities Plus
Velocity American
Vitol
Westar Energy
Western Area Power Administration - Rocky Mountain Regio
Western Area Power Administration - Upper Great Plains Marl
Western Area Power Administration
Western Farmers Electric Cooperative
XO Energy SW
XO Energy SW2

Appendix B: Illustration of Southwest Power Pool Integrated Market

Market Participants submit bids for both their load and generation for each hour in the day-ahead market. Suppose an SPP Market Participant (MP) forecasts that their load (demand) for the following day at hour-12 will be 2,300 MWh. The MP submits a bid for their load into the day-ahead market for hour-12 the following day for 2,000 MWh (SPP does not require that 100% of the forecasted load be bid into the day-ahead market). The SPP will purchase the remaining 300 MWh forecasted load in the real-time market.

SPP requires the MP to submit generation bids into the day-ahead market with at least enough generation (capacity) to meet 112% of the load that was bid into the day-ahead market (2,240 MWh) for hour-12. The 112% requirement is to ensure that there is enough margin for reliability in case the demand is higher than expected. In the illustrative example below, the MP bids in the following generation into the day-ahead market for hour-12:

Table B1: Illustrative example of MP bids for generation into the day-ahead market for hour-12

	Amount	Marginal Cost of Production2	Cost of Production
Wind	200 MWh1	$0/MWh	$20.003/MWh
Nuclear4	800 MWh	$8.90/MWh	$45.00/MWh
Large Coal	1,350 MWh	$13.15/MWh	$26.35/MWh
Small Coal	225 MWh	$21.00/MWh	$54.85/MWh
Combined Cycle	250 MWh	$42.75/MWh	$160.55/MWh

1 Wind generation is only credited 10% of rated nameplate or 20 MW toward the 2,240 MWh bid requirement
2 SPP generation bid price only includes fuel and variable operation & maintenance costs
3 This is recent Power Purchase Agreement cost for wind generation
4 Nuclear is considered "must-run" or a "price-taker" so it will dispatch regardless of market price

Based on the above table, the MP bid 2,645 MWh of generation into the day-ahead market. This is more than 2,240 MWh the SPP day-ahead required for supplying the MP load.

For example, if the day-ahead market price for hour-12 is determined to be $18.00/MWh based on the generation bids received from all the SPP Market Participants. SPP will dispatch the generation with marginal cost of production at or below $18.00/MWh. Based upon the information above, SPP will dispatch the MP wind, nuclear, and large coal. The MP will still purchase 2,000 MWh from the day-ahead market to serve the load they bid into the SPP day-ahead market. All the generation that is dispatched by SPP will receive $18.00/MWh for the output from their generation. Note that the cost of production for generation that was dispatched by SPP is, in this illustration, more than the market price of $18.00/MWh, except for wind generation. This means that the market price did not cover the cost of the MP to own the generation for other sources.

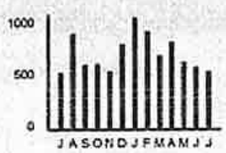
If the marginal cost of production for generation is greater than the day-ahead market price, the MP purchases electricity cheaper from the day-ahead market than it would cost them to produce the electricity themselves (for Small Coal, $21.00/MWh to produce vs. $18.00/MWh to purchase). The MP generation that SPP did not dispatch, Small Coal and Combined Cycle, did not receive any revenue from the day-ahead market and incurred fixed costs during this period.

Appendix C: Example of an Unbundled Bill

ComEd.
An Exelon Company

www.comed.com
Customer Service / Power Outage
English
1-800-EDISON1 (1-800-334-7661)
Español
1-800-95-LUCES (1-800-955-8237)
Hearing/Speech Impaired
1-800-572-5789 (TTY)
For Electric Supply Choices visit
www.pluginillinois.org

Your Usage Profile
13-Month Usage (Total kWh)



Electric Usage

Month	kWh
Aug-12	565
Sep-12	505
Oct-12	270
Nov-12	305
Dec-12	425
Jan-13	850
Feb-13	800
Mar-13	830
Apr-13	545
May-13	510
Jun-13	375
Jul-13	565
Aug-13	800

Month Billed	Average Daily kWh	Temp
Last Year	19	75
Last Month	18	61
Current Month	27	83

Page 1 of 2
Account Number 9999999999
Name
Service Location
Phone Number

Bill Summary	
Previous Balance	$72.16
Total Payments - Thank You	$72.16
Amount Due on August 22, 2013	$81.62

Issue Date August 1, 2013

Meter Information

Read Date	Meter Number	Load Type	Reading Type	Meter Reading Previous	Present	Difference	Multiplier X	Usage
8/1	99999999	General Service	Total kWh	69103	69903	800	1	800

Service from 07/02/2013 to 08/01/2013 - 30Days | Residential - Single

Electricity Supply Services				**$44.09**
Electricity Supply Charge	800 kWh		0.04597	36.78
Transmission Services Charge	800 kWh	X	0.00914	7.31
Purchased Electricity Adjustment				0.00
Delivery Services - ComEd				**$32.09**
Customer Charge				12.78
Standard Metering Charge				2.86
Distribution Facilities Charge	800 kWh	X	0.01936	15.49
IL Electricity Distribution Charge	800 kWh	X	0.00120	0.96
Taxes and Other				**$5.44**
Environmental Cost Recovery Adj	800 kWh	X	0.00056	0.45
Energy Efficiency Programs	800 kWh	X	0.00186	1.49
Franchise Cost	$31.52	X	2.72100%	0.86
State Tax				2.64
Total Current Charges				**$81.62**

(continued on next page)

Return only this portion with your check made payable to ComEd. Please write your account number on your check.

ComEd.
An Exelon Company

99999 9999 90000 0000

John Doe
123 E. Main St
Anytown, IL 99999-0000

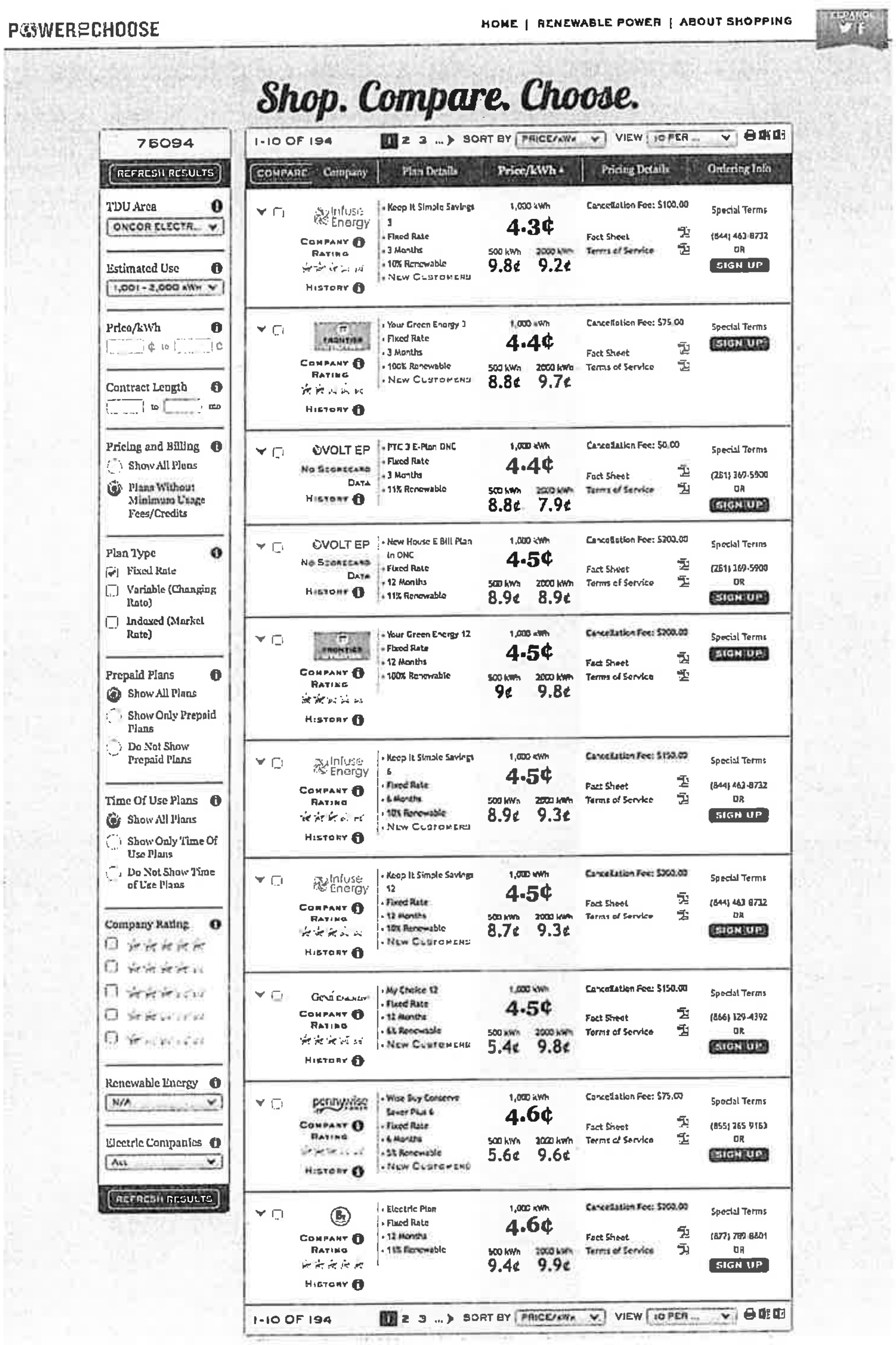
Account Number
9999999999

Payment Amount

Please pay this amount by 08/22/2013 $81.62

ComEd
PO Box 6111
Carol Stream, IL 60197-6111

Appendix D: Screenshot of powertochoose.org showing suppliers' rate options



Appendix E: 2015 utility bundled retail sales - residential

2015 Utility Bundled Retail Sales- Residential

(Data from forms EIA-861- schedules 4A & 4D and EIA-861S)

Entity	State	Ownership	Customers (Count)	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/kWh)
Auburn Board of Public Works	NE	Municipal	1,904	24,543	2,229.0	9.08
Burt County Public Power Dist	NE	Political Subdivision	3,341	57,379	7,485.0	13.04
Butler Public Power District - (NE)	NE	Political Subdivision	4,603	60,903	6,778.0	11.13
Cedar-Knox Public Power Dist	NE	Political Subdivision	5,422	95,184	8,137.0	8.55
Cherry-Todd Electric Coop, Inc	NE	Cooperative	827	8,605	1,028.9	11.96
Chimney Rock Public Power Dist	NE	Political Subdivision	1,981	22,178	3,496.0	15.76
City of Alliance- (NE)	NE	Municipal	4,185	38,856	4,811.8	12.38
City of Beatrice - (NE)	NE	Municipal	5,782	67,896	6,458.0	9.51
City of Broken Bow - (NE)	NE	Municipal	1,896	22,092	2,182.6	9.88
City of Cambridge - (NE)	NE	Municipal	481	5,621	608.0	10.82
City of Central City	NE	Municipal	1,370	16,660	1,700.4	10.21
City of Crete	NE	Municipal	2,444	25,264	2,313.0	9.16
City of David City	NE	Municipal	1,207	14,264	1,658.0	11.62
City of Fairbury	NE	Municipal	2,672	30,922	3,235.0	10.46
City of Falls City - (NE)	NE	Municipal	2,135	24,033	1,959.0	8.15
City of Fremont - (NE)	NE	Municipal	12,345	136,546	12,646.0	9.26
City of Gering - (NE)	NE	Municipal	3,439	32,648	4,975.0	15.24
City of Gothenburg - (NE)	NE	Municipal	1,486	19,973	1,644.0	8.23
City of Grand Island - (NE)	NE	Municipal	21,467	213,241	20,960.0	9.83
City of Hastings - (NE)	NE	Municipal	10,882	108,725	10,058.1	9.25
City of Hebron - (NE)	NE	Municipal	743	8,756	805.0	9.19
City of Holdrege	NE	Municipal	2,564	28,541	2,675.4	9.37
City of Imperial	NE	Municipal	1,040	11,630	1,205.0	10.36
City of Kimball - (NE)	NE	Municipal	1,445	9,938	1,548.0	15.58
City of Lexington - (NE)	NE	Municipal	3,436	48,412	4,914.7	10.15
City of Madison - (NE)	NE	Municipal	793	9,420	897.0	9.52
City of Minden - (NE)	NE	Municipal	1,321	14,261	1,877.7	13.17
City of Nebraska City	NE	Municipal	4,759	52,445	5,692.5	10.85
City of Neligh - (NE)	NE	Municipal	869	9,207	961.0	10.44
City of North Platte	NE	Municipal	11,269	117,841	11,768.0	9.99
City of Ord - (NE)	NE	Municipal	1,126	15,973	1,371.0	8.58
City of Pierce - (NE)	NE	Municipal	999	12,057	1,050.0	8.71
City of Schuyler - (NE)	NE	Municipal	2,112	27,919	2,633.0	9.43
City of Seward - (NE)	NE	Municipal	2,788	28,494	3,312.0	11.62
City of Sidney - (NE)	NE	Municipal	4,065	29,986	3,692.0	12.31
City of South Sioux City	NE	Municipal	4,686	68,516	6,931.0	10.12
City of St Paul - (NE)	NE	Municipal	954	11,112	1,152.0	10.37
City of Superior - (NE)	NE	Municipal	1,023	9,608	1,047.0	10.90
City of Syracuse - (NE)	NE	Municipal	1,071	8,802	983.0	11.17
City of Tecumseh	NE	Municipal	809	7,920	954.3	12.05
City of Valentine - (NE)	NE	Municipal	1,422	22,017	1,939.7	8.81
City of Wahoo - (NE)	NE	Municipal	1,878	21,926	1,897.0	8.65
City of Wakefield - (NE)	NE	Municipal	566	4,676	507.4	10.85
City of Wayne	NE	Municipal	2,019	17,951	1,989.0	11.08
City of West Point - (NE)	NE	Municipal	1,490	14,430	1,677.0	11.62
Cornhusker Public Power Dist	NE	Political Subdivision	7,054	122,722	13,558.0	11.05
Cozad Board of Public Works	NE	Municipal	1,708	20,404	2,140.1	10.49
Cuming County Public Pwr Dist	NE	Political Subdivision	2,791	48,443	4,817.8	9.95
Custer Public Power District	NE	Political Subdivision	4,598	72,438	8,320.0	11.49
Dawson Power District	NE	Political Subdivision	15,642	237,391	24,392.0	10.28
Elkhorn Rural Public Pwr Dist	NE	Political Subdivision	5,917	103,210	10,150.0	9.83
High West Energy, Inc	NE	Cooperative	1,778	17,815	2,274.0	12.76
Highline Electric Assn	NE	Cooperative	751	8,162	1,009.3	12.37
Howard Greeley Rural P P D	NE	Political Subdivision	3,218	52,850	5,685.0	10.76
KBR Rural Public Power District	NE	Political Subdivision	3,345	35,811	4,765.0	13.31
LaCreek Electric Assn, Inc	NE	Cooperative	168	2,263	242.0	10.69
Lincoln Electric System	NE	Municipal	117,859	1,168,564	110,421.3	9.45
Loup River Public Power Dist	NE	Political Subdivision	14,993	227,342	22,541.0	9.92
Loup Valleys Rural P P D	NE	Political Subdivision	2,854	39,334	4,442.0	11.29
McCook Public Power District	NE	Political Subdivision	3,734	37,445	4,839.6	12.92
Midwest Electric Member Corp	NE	Cooperative	3,195	33,805	3,865.3	11.43
Nebraska Public Power District	NE	Political Subdivision	70,318	793,831	84,858.0	10.69
Niobrara Valley El Member Corp	NE	Cooperative	4,786	49,709	5,804.0	11.68
Norris Public Power District	NE	Political Subdivision	12,920	240,805	22,917.1	9.52
North Central Public Pwr Dist	NE	Political Subdivision	3,504	40,981	4,830.5	11.79
Northeast Nebraska P P D	NE	Political Subdivision	6,713	114,287	11,554.0	10.11
Northwest Rural Pub Pwr Dist	NE	Political Subdivision	1,439	20,529	3,038.6	14.80
Omaha Public Power District	NE	Political Subdivision	319,501	3,452,484	382,260.0	11.07
Panhandle Rural El Member Assn	NE	Cooperative	1,766	29,749	3,788.0	12.73
Perennial Public Power Dist	NE	Political Subdivision	3,587	64,402	6,303.0	9.79
Polk County Rural Pub Pwr Dist	NE	Political Subdivision	2,859	41,046	4,694.5	11.44
Roosevelt Public Power Dist	NE	Political Subdivision	2,081	29,726	3,509.0	11.80
Seward County Rrl Pub Pwr Dist	NE	Political Subdivision	3,152	56,679	5,988.0	10.56
South Central Public Pwr Dist	NE	Political Subdivision	3,802	62,198	5,793.5	9.31
Southern Public Power District	NE	Political Subdivision	15,045	233,136	23,455.9	10.06
Southwest Public Power Dist	NE	Political Subdivision	2,247	34,644	3,492.0	10.08
Stanton County Public Pwr Dist	NE	Political Subdivision	1,788	28,177	3,174.0	11.26
Twin Valleys Public Power Dist	NE	Political Subdivision	4,106	36,693	4,338.0	11.82
Wheat Belt Public Power Dist	NE	Political Subdivision	3,235	33,907	4,307.8	12.70
Wyrulec Company	NE	Cooperative	269	2,722	407.0	14.95
Adjustment 2015	NE	Other	28,101	301,053	34,709.1	

Appendix F: 2015 utility bundled retail sales - Industrial

2015 Utility Bundled Retail Sales- Industrial

(Data from forms EIA-861- schedules 4A & 4D and EIA-861S)

Entity	State	Ownership	Customers (Count)	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/kWh)
Auburn Board of Public Works	NE	Municipal	1	2,904	262.8	9.05
Burt County Public Power Dist	NE	Political Subdivision	665	22,750	3,413.0	15.00
Butler Public Power District - (NE)	NE	Political Subdivision	666	8,921	2,553.0	28.62
Cedar-Knox Public Power Dist	NE	Political Subdivision	1,198	24,805	3,774.0	15.21
Cherry-Todd Electric Coop, Inc	NE	Cooperative	226	16,566	2,032.1	12.27
Chimney Rock Public Power Dist	NE	Political Subdivision	928	18,039	2,361.0	13.09
City of Alliance- (NE)	NE	Municipal	12	29,093	2,868.4	9.86
City of Beatrice - (NE)	NE	Municipal	119	69,163	5,325.0	7.70
City of Broken Bow - (NE)	NE	Municipal	8	52,275	3,738.8	7.15
City of Cambridge - (NE)	NE	Municipal	1	33,788	2,059.0	6.09
City of Central City	NE	Municipal	11	5,851	609.0	10.41
City of Crete	NE	Municipal	3	63,323	4,062.0	6.41
City of David City	NE	Municipal	30	18,179	1,871.0	10.29
City of Fairbury	NE	Municipal	18	31,762	2,465.0	7.76
City of Falls City - (NE)	NE	Municipal	7	4,278	298.0	6.97
City of Fremont - (NE)	NE	Municipal	530	230,816	16,910.0	7.33
City of Gering - (NE)	NE	Municipal	40	18,185	2,085.0	11.47
City of Gothenburg - (NE)	NE	Municipal	15	22,654	1,889.0	8.34
City of Grand Island - (NE)	NE	Municipal	99	317,928	23,554.0	7.41
City of Hastings - (NE)	NE	Municipal	128	180,698	11,145.5	6.17
City of Holdrege	NE	Municipal	2	54,208	2,625.2	4.84
City of Imperial	NE	Municipal	45	4,321	357.0	8.26
City of Lexington - (NE)	NE	Municipal	5	115,517	7,792.3	6.75
City of Madison - (NE)	NE	Municipal	1	45,108	3,010.0	6.67
City of Nebraska City	NE	Municipal	34	69,297	5,922.0	8.55
City of North Platte	NE	Municipal	4	38,521	2,664.0	6.92
City of Pierce - (NE)	NE	Municipal	28	609	36.0	5.91
City of Schuyler - (NE)	NE	Municipal	127	97,418	7,295.0	7.49
City of Seward - (NE)	NE	Municipal	5	29,559	2,460.0	8.32
City of Sidney - (NE)	NE	Municipal	67	36,138	2,793.0	7.73
City of St Paul - (NE)	NE	Municipal	32	8,908	802.0	9.00
City of Superior - (NE)	NE	Municipal	15	6,017	560.0	9.31
City of Syracuse - (NE)	NE	Municipal	19	5,798	454.0	7.83
City of Tecumseh	NE	Municipal	5	7,485	643.8	8.60
City of Wahoo - (NE)	NE	Municipal	4	12,533	935.0	7.46
City of Wakefield - (NE)	NE	Municipal	1	36,630	2,556.0	6.98
City of West Point - (NE)	NE	Municipal	80	31,330	2,947.0	9.41
Cornhusker Public Power Dist	NE	Political Subdivision	2,287	152,835	14,106.0	9.23
Cozad Board of Public Works	NE	Municipal	1	4,301	371.8	8.64
Cuming County Public Pwr Dist	NE	Political Subdivision	326	14,653	1,688.4	11.52
Custer Public Power District	NE	Political Subdivision	4,911	98,225	13,236.0	13.48
Dawson Power District	NE	Political Subdivision	5,795	241,846	27,821.0	11.50
Elkhorn Rural Public Pwr Dist	NE	Political Subdivision	2,807	109,716	12,773.0	11.64
High West Energy, Inc	NE	Cooperative	1,198	71,167	8,048.0	11.31
Highline Electric Assn	NE	Cooperative	1,084	63,788	8,138.7	12.76
Howard Greeley Rural P P D	NE	Political Subdivision	1,445	39,213	4,140.0	10.56
KBR Rural Public Power District	NE	Political Subdivision	779	34,562	5,631.0	16.29
LaCreek Electric Assn, Inc	NE	Cooperative	46	2,432	277.0	11.39
Lincoln Electric System	NE	Municipal	184	487,115	32,121.3	6.59
Loup River Public Power Dist	NE	Political Subdivision	53	662,298	42,513.0	6.42
Loup Valleys Rural P P D	NE	Political Subdivision	2,245	72,081	7,113.0	9.87
McCook Public Power District	NE	Political Subdivision	910	101,832	8,620.5	8.47
Midwest Electric Member Corp	NE	Cooperative	2,058	141,936	17,330.1	12.21
Nebraska Public Power District	NE	Political Subdivision	56	1,170,406	66,056.0	5.64
Niobrara Valley El Member Corp	NE	Cooperative	1,203	64,229	7,544.0	11.75
Norris Public Power District	NE	Political Subdivision	1,869	460,966	33,847.5	7.34
North Central Public Pwr Dist	NE	Political Subdivision	1,109	38,128	5,903.1	15.48
Northeast Nebraska P P D	NE	Political Subdivision	673	12,689	2,341.0	18.45
Northwest Rural Pub Pwr Dist	NE	Political Subdivision	652	45,414	5,843.0	12.87
Omaha Public Power District	NE	Political Subdivision	174	3,299,315	201,969.0	6.12
Panhandle Rural El Member Assn	NE	Cooperative	847	36,869	6,048.0	16.40
Perennial Public Power Dist	NE	Political Subdivision	2,709	194,047	16,590.0	8.55
Polk County Rural Pub Pwr Dist	NE	Political Subdivision	1,289	21,702	4,335.4	19.98
Roosevelt Public Power Dist	NE	Political Subdivision	684	18,498	2,246.0	12.14
Seward County Rrl Pub Pwr Dist	NE	Political Subdivision	757	9,933	1,863.0	18.76
South Central Public Pwr Dist	NE	Political Subdivision	3,129	74,072	8,547.8	11.54
Southern Public Power District	NE	Political Subdivision	9,359	767,508	64,605.8	8.42
Southwest Public Power Dist	NE	Political Subdivision	1,280	116,678	12,314.0	10.55
Stanton County Public Pwr Dist	NE	Political Subdivision	594	93,517	7,461.0	7.98
Twin Valleys Public Power Dist	NE	Political Subdivision	1,246	27,471	4,768.0	17.36
WAPA-- Western Area Power Administration	NE	Federal	1	3,982	32.0	0.80
Wheat Belt Public Power Dist	NE	Political Subdivision	1,014	87,579	10,170.7	11.61
Wyrulec Company	NE	Cooperative	164	4,070	616.4	15.14
Y-W Electric Assn Inc	NE	Cooperative	72	6,131	774.0	12.62
Adjustment 2015	NE	Other	349	32,528	3,888.0	

Appendix G: Researchers' Biographies

Ernie Goss is the Jack MacAllister Chair in Regional Economics at Creighton University and is the initial director for Creighton's Institute for Economic Inquiry. He is also principal of the Goss Institute in Denver, Colo. Goss received his Ph.D. in economics from The University of Tennessee in 1983 and is a former faculty research fellow at NASA's Marshall Space Flight Center. He was a visiting scholar with the Congressional Budget Office for 2003-2004, and has testified before the U.S. Congress, the Kansas Legislature, and the Nebraska Legislature. In the fall of 2005, the Nebraska Attorney General appointed Goss to head a task force examining gasoline pricing in the state.

He has published more than 100 research studies focusing primarily on economic forecasting and on the statistical analysis of business and economic data. His book Changing Attitudes Toward Economic Reform During the Yeltsin Era was published by Praeger Press in 2003, and his book Governing Fortune: Casino Gambling in America was published by the University of Michigan Press in March 2007.

He is editor of Economic Trends, an economics newsletter published monthly with more than 11,000 subscribers, produces a monthly business conditions index for the nine-state Mid-American region, and conducts a survey of bank CEOs in 10 U.S. states. Survey and index results are cited each month in approximately 100 newspapers; citations have included the New York Times, Wall Street Journal, Investors Business Daily, The Christian Science Monitor, Chicago Sun Times, and other national and regional newspapers and magazines. Each month 75-100 radio stations carry his Regional Economic Report.

Jeffrey Milewski is a senior research economist at Goss & Associates. He received his master's degree in political economy from the London School of Economics and Political Science in 2013. He completed his bachelor's degree at Creighton University in 2007, having studied economics and finance. Milewski also has experience working in finance and as an entrepreneur. Recently, he has co-authored impact studies on a range of topics such as property-casualty insurance, highway expansion, cost/benefit analysis, and national sporting events.

APPENDIX NO. 24

Performance of the New England Power Grid During Extreme Cold

Performance of the New England power grid during extreme cold Dec 25-Jan 8

January 26, 2018 By Rod Adams — 22 Comments

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The Independent System Operator for the New England power grid (ISO-NE) has produced a summary brief describing the challenges associated with Arctic Outbreak 2017-2018, a period of substantially below normal temperatures that lasted from Dec.25, 2017 until Jan. 8, 2018.

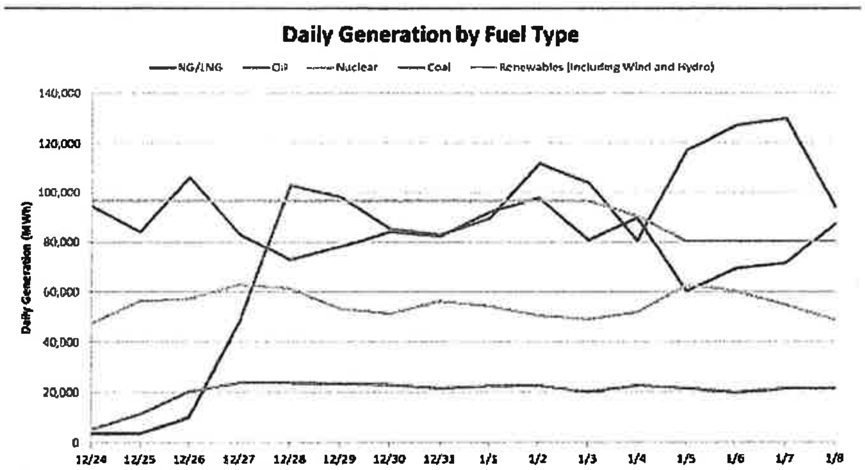
After describing the intensity of the cold wave with a number of graphs, charts, images and words, the brief made the following sobering statements about the fuel mix used to supply power demand.

- Overall, there was significantly higher than normal use of oil
  – Coal use also increased over normal use

- Gas and Oil fuel price inversion led to oil being in economic merit and base loaded
- As gas became uneconomic, the entire season's oil supply rapidly depleted

The brief includes the following graph showing the daily electricity contribution in MWhrs from various fuel sources.

Daily Generation by Fuel Type (MWh)



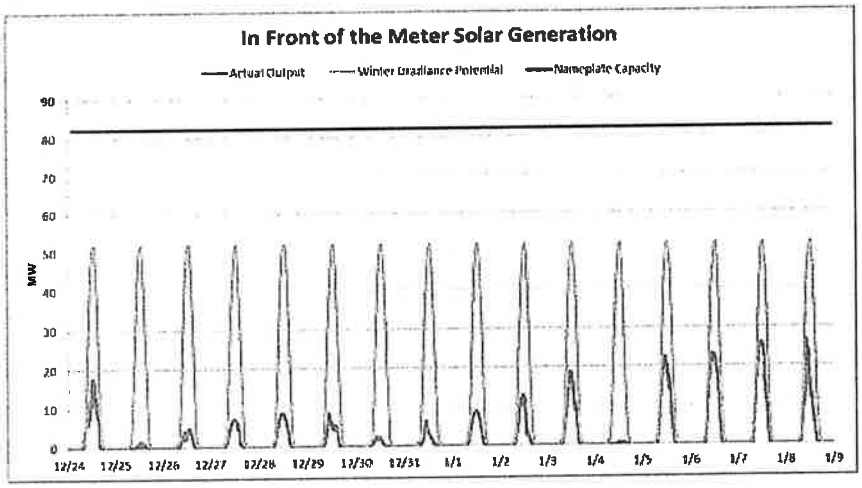
A major contributing factor to the rapid depletion of fuel inventories was the sharp increase in oil-fueled power production starting on Jan 4. Nuclear electricity production dropped on Jan 4 by about 8,000 MWhrs and dropped again on Jan 5 by roughly the same amount.

Pilgrim Nuclear Power Plant was scrammed at about 1:15 pm on Jan 4 because one of its two large transmission lines fell down during Winter Storm Grayson. The plant, which had been running continuously at or near full **power** for 225 days, was not returned to service until Jan 10 and did not achieve full **power** output until Jan 12.

The majority of **the power** that had been supplied by Pilgrim was replaced by burning more oil. As **the** winter storm moved away from **the** region, generation from wind also fell.

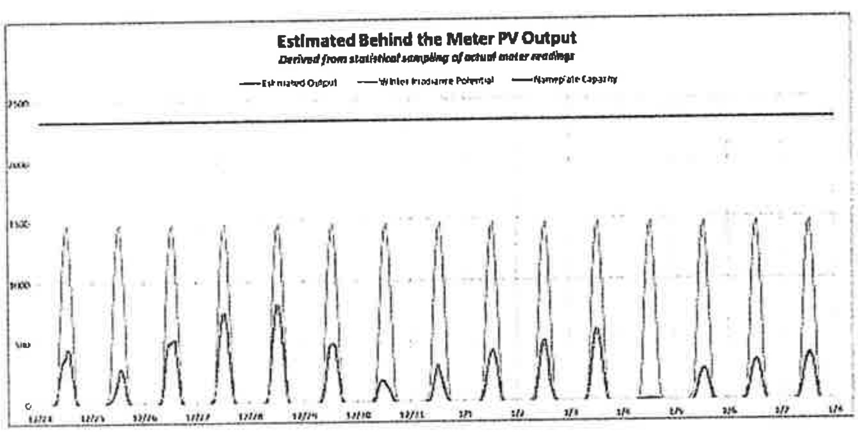
The below pair of charts from **the** brief should also be food for thought for those who claim that what regions like **New England** really need is more solar **power**.

PV Generation – In Front of the Meter



*Note: PV resources in front of **the** meter are intended for supplying **the grid**.*

PV Generation – Behind the Meter



*Note: PV behind **the** meter are intended mainly for on-site generation.*

Fuel supply challenges

Though **there** were no large scale **power** outages, keeping **power** flowing to customers required some heroic efforts on **the** part of fuel truck drivers, Coast Guard ice breakers, and **power** plant operators.

It even required **the** suspension of usual rush hour traffic procedures that prevent **the** Weymouth Fore River Bridge from opening. As **the** Coast Guard explained in its press release announcing **the** temporary allowance for critical vessel traffic, "...recent extreme weather and ice accumulation in **the** Weymouth Fore River has made it difficult for tank vessels and barges to deliver time-sensitive resources such as home heating oil and kerosene, and fuel for **power** plants and public transit."

Even though road conditions were treacherous, fuel trucks were pressed into overtime service to prevent the catastrophic consequences of running out of fuel during an event where temperatures were often well below 0 °F and the wind was howling. Keeping fuel oil supplied to homes, businesses and power generators required the suspension of normal driver rest requirements.

The ISO-NE brief describes trucking as the main fuel supply logistical constraint and states that:

- Carriers are at their physical limits
- Drivers need time off to rest, even with State Waivers in effect
- The break in the weather this week [beginning Jan 8] will provide much needed relief

Both the rush hour bridge openings and the suspension of truck driver rest rules had the potential to alert large segments of the population to the fact that their electricity supply system was closer to collapse than sunny summary statements of "reliable performance" might imply. Fortunately, no tragic consequences occurred – this time.

Not a perfect storm

Though the weather event was unusual, it was certainly not unprecedented. It's no surprise to note that it sometimes gets cold and dark in New England during the winter. There are some who incorrectly label the entire event as a "bomb cyclone," overlooking the fact that moniker only applies to the rather strong nor'easter that raced up the Eastern Seaboard on Jan 4.

Others with longer memories apply a more accurate label of "New England winter," to reflect the fact that winter weather can vary from year to year, but it is something that requires routine preparations. It isn't a surprising act of God when it is a little colder than average, just as it shouldn't be surprising when a winter ends up to be a bit warmer than average.

Senate Energy and Commerce Committee Hearing

On Tuesday, Jan 23, 2018, Senator Lisa Murkowski, the Chair of the Senate Energy and Natural Resources Committee, convened a hearing to discuss the performance of the electric power grid during certain weather conditions. Most of the testimony and questioning focused on the two week period from Dec 25-Jan 8, but the nature of the topic allowed participants to expand the discussion to other memorable weather events including droughts, heat waves and tropical cyclones.

Though it's possible for people to watch the archived video of the hearing and find reassuring commentary confirming whatever biases they have, I watched with growing concerns for New England's ability to handle routine weather events without major economic disruption and potential loss of life. (I'll admit that my training as a professional worrier – also known as an engineering officer in the Nuclear Navy – biases me toward concern when others are complacent.)

Mr. Gordon van Weile, the president and CEO of ISO-NE, provided both stark warnings for the future and a reminder that he has been sounding the warnings since at least 2013 without any substantive action being taken. Each time a non-gas fired generator retires, the situation gets more fragile. That is especially true when the retiring resource is a nuclear plant that has been reliably running at full power 80-95% of the time.

When there is a sustained cold weather event, natural gas availability hits a virtual wall where prices rise at astronomical rates indicating that there is no gas left to be purchased, no matter how much the buyer is willing and able to pay. When prices in a region rise to be 20 or more times higher on one side of a pipe compared to the other, it means there is no more room in the pipe.

Mr. van Weile described the precarious nature of New England's fuel supply during the cold spell.

> *While we weathered a stretch of extremely cold weather and a blizzard, we remain concerned about resupply of these resources during the remainder of the*

> *winter season and are in close coordination with state and federal officials about* ***the*** *challenges of ensuring adequate oil supplies to* ***the*** *region. Finally, given* ***the*** *fuel constraints,* ***the*** *rapid depletion of* ***the*** *oil inventory, and* ***the*** *reality that resupply was several days away during* ***the*** *peak of* ***the*** *cold weather period, our biggest operating concern was that we would experience a large, multi-day system contingency during this period or that oil-fired generators would run out of fuel before* ***they*** *could be resupplied.*

Pilgrim's Jan 4-Jan 9 Shutdown

It's difficult, even during a period of incredibly steady **performance** by 98 out of 99 nuclear plants, to engage in discussions about **the** importance of nuclear energy for **the** resilience of **the** U.S. **power grid** when **the** 99th plant shuts down unexpectedly and remains shutdown for what is now going on six days.

paraphrasing a nuclear industry cliche, during a weather event an outage anywhere is an outage everywhere. That is especially true when it is unplanned and lasts an unexpectedly long time.

On **the** afternoon of January 4, **the** Pilgrim Nuclear Plant operators manually shut down **their** **power** station as a result of what I would term an overabundance of caution and fear of criticism from life-long opponents. **The** plant was returned to service almost six days later. Though **the** transmission line was back in service in approximately two days, **the** shutdown was extended because **the** plant operators decided to repair a small steam leak.

Aside: Steam plants leak. It is **the** nature of **the** technology. That is especially true as plants age. In many cases, **the** leaks are a minor annoyance and repairs can be deferred with no fixed deadline. It's dependent on situation; during one of my patrols we managed a rather irritating steam leak for more than a month so we could complete our scheduled mission. **End Aside.**

Investigation into details of Pilgrim's shutdown

The specific instigator of **the** decision to shut down was **the** loss of one of two 345 kV transmission lines that allow Pilgrim to deliver its **power** to **the grid**.

There is no external or regulatory requirement for a nuclear plant of Pilgrim's design to immediately shut down in such a circumstance. **The** required action is to work diligently on restoring **the** line and to limit **the** duration of operations with just one outgoing transmission line to a period of 72 hours. If **the** nature of **the** failure is such that it is unlikely to be resolved in **the** allowed time, most operators will choose to shutdown once that fact is known.

Pilgrim, however, has a local procedure that requires a prompt manual shutdown if it loses either one of its outgoing transmission lines during a storm event. According to Patrick O'Brien, that procedure was developed based on past operating experience. When one transmission line goes down, **the** plant is in a condition where **the** loss of **the** second line would result in an automatic trip and a more significant cycle on **the** plant's systems.

In response to a question about **the** possibility of delaying such a shutdown in a case where **the** **grid** operator had declared that **the power** was needed and shutdowns should be avoided, Mr. O'Brien stated that **there** is no process to allow situational judgement by plant operators. He acknowledged that **there** is a process by which a local procedure could be changed, but that requires a full impact review that cannot be waived.

During most of **the** period that Pilgrim was shutdown and completing **the** deferrable repair, **the** wholesale price of electricity in **New England** and **New** York averaged approximately $200 per MWh. As demonstrated during a separate period of demand caused by similarly cold weather with **the** plant operating, it is reasonable to state that lack of supply from Pilgrim added something close to $100/MWe to wholesale **power** prices.

If this analysis is correct, **the** loss of Pilgrim at a time of high demand cost **New England** customers approximately $1.5 million per hour. (Roughly 15,000 MW of demand x $100/MWh) On **the** other side of **the** ledger, a number of entities associated with fuel deliveries and **power** generators collected an extra $1.5 million per hour for six profitable days.

When operating, Pilgrim's daily electricity production is **the** energy equivalent of approximately 9,300 barrels of oil. Delivering that much oil to **the** generators that needed to run to replace Pilgrim required **the** logistic supply capacity equivalent of almost 50 large tanker trucks each day.

Pilgrim is scheduled to permanently close in early June 2019. Entergy, **the** plant's owner, has determined it is not profitable enough to overcome **the** costs, risks and managerial annoyances associated with operating **the** plant.

A loud and persistent subset of its neighbors has been vocally opposed to **the** plant's existence since before it was built.

Some of those neighbors vehemently and publicly protested Entergy's failure to shutdown **the** plant ***before*** **the** winter storm hit, claiming that **the** operators were putting profit over safety. When **the** plant did shutdown, those opponents did not petition for it to be restarted as soon as possible to keep **the power grid** secure, air pollution levels down, and electricity prices in check.

Instead, **they** staged a protest suggesting that **the** plant should be forced to remain shutdown and enter decommissioning a year ahead of **the** already premature date.

Here are excerpts from an email from Dianne Turco, **the** executive director of Cape Downwinders, explaining her organization's position regarding Pilgrim specifically and nuclear energy in general.

> *As an organization, Cape Downwinders is focused on public health and safety regarding **the** operation of Pilgrim. We support clean, green, renewable, and safe energy. Nuclear certainly does not fit in that category.*
>
> ...
>
> *It should be no surprise if Pilgrim goes down during a storm. That is one of **the** reasons why **they** are rated so low. In fact, in **the** past few storms, Entergy voluntarily shut Pilgrim preemptively. But not this time. **They** took **the** risk that threatens our entire region. Also, Pilgrim is not reliable baseload energy. When needed **the** most, Pilgrim has shutdown during blizzards and during **the** warmest days of **the** year due to temperature rise in Cape Cod Bay that interferes with **the** cooling water.*
>
> ...
>
> *Cape Downwinders position on energy is certainly no nuclear. Release of radioactive isotopes into **the** environment are part of **the** operation of a reactor. **The** National Academy of Science has determined **there** is no safe dose of ionizing radiation. Studies have shown cancer increases around nuclear reactors and after nuclear accidents. Dr. Richard Clapp, who was head of **the** MA Cancer Registry, found **the** closer one lived or worked in relation to Pilgrim, **the** incidence of cancer was 400% higher. We need clean, green, safe, and renewable energy for a healthy planet. Neither nuclear nor fossil fuels meet that criteria.*

I wasn't too surprised when she did not respond to my follow-up email.

> *Ms Turco*
>
> *Thank you for your response.*
>
> *This morning, when I checked **the** dashboards published by ISO-NE giving real time information on electricity and fuel sources, only 7% of **the grid** supply came*

from non hydro renewables. Nuclear and gas were each supplying 33%, oil and coal combined for 27%.

93% of that 7% came from burning wood, refuse or landfill gas. 7% came from wind, 0% from solar.

*You have **the** luxury of advocating. Fortunately, **the**re are other people working hard to supply reliable electricity from capable sources – nuclear, natural gas, oil and coal.*

***The** NAS says that evidence shows that radiation doses above 100 mSv can increase **the** risk of cancer. **They** also say that **the** risk increase is proportional to dose.*

***They** say **the**re is not enough evidence to conclusively show a threshold, so **they** make a conservative assumption and extend **the** proportional line down to zero risk at zero dose.*

*That means that risk is never zero, but approaches zero as doses approach **the** range of public exposure from nuclear **power** plants.*

*It is much, much lower than **the** health risk of exposure to below freezing temperatures.*

*Pilgrim is one of **the** worst licensed nuclear plants in **the** US, but it isn't unsafe any more than **the** worst player in **the** NFL is an unhealthy couch potato.*

Rod Adams

With persistent opponents like Ms. Turco, it's understandable that a company might make **the** decision to exit. Operating **power** plants is hard enough when people occasionally express **the**ir appreciation for reliable service. It can be downright depressing to field sharp criticism for being unreliable after running for 226 days straight and maintaining a capacity factor in **the** neighborhood of 85% over a sustained period of years.

Why did Entergy take its time in returning Pilgrim to service?

Despite several attempts, I have been unable to determine the specific reasons why Entergy decided that they should take the opportunity presented by the downed power line to perform a repair that kept them from collecting revenues associated with generating power during a time of high demand and high prices.

It's not a simple task to determine just how much money Entergy left on the table by not operating. It isn't correct to simply take the wholesale price history and multiply it by Pilgrim's 685 MWe capacity because the prices would have been lower if Pilgrim had been operating.

However, it's clear that the steam leak repair cost several million per day in forgone revenues. Perhaps there were people in the decision chain that were reluctant to maximize their profits in the plant's final years of operation because they did not want anyone to suggest that the shutdown decision was based on economics that had been overcome by events.

Filed Under: Grid resilience

About Rod Adams

APPENDIX NO. 25

The Perils of “Electrify Everything”,

The Topeka Capital-Journal

Feb. 21, 2021

THE TOPEKA CAPITAL-JOURNAL

Opinion

Edward Cross: The Perils of "Electrify Everything"

By Edward Cross / Special toThe Capital-Journal
February 21, 2021

In Mid-February, an arctic blast swept across Kansas and the nation and gave America a preview of what an "existential threat" looks like. Not the kind of fear-mongering "12-years to the end of the earth" threat by the likes of U.S. Representative Alexandra Ocasio-Cortez and fed to Americans by President Biden as he issues job-killing executive orders.

The threat we saw in February took away people's power, heat, and clean water. The blame lies with those who irresponsibly push not-ready-for-primetime renewable energy, like wind and solar power, to make up a greater share of our energy grids.

There is a lot of conflicting information about electricity blackouts across the nation. The root cause of the blackouts in Kansas and across the nation is national and state policy that has prioritized the adoption of unreliable wind/solar energy over reliable energy.

For the last decade-plus energy policy in Kansas and the U.S. has been focused on mandating or subsidizing as much wind and solar as possible.

The focus on wind has come above all at the expense of coal, natural gas, and nuclear which has the resiliency advantage of being able to store large quantities of fuel onsite.

Because intermittent wind and solar can always go near zero, as we saw in mid-February, they don't replace the cost of reliable power plants, they add to the cost of reliable power plants. This is why the more wind and solar grids are used, the higher their electricity prices.

To lessen the price increases from unreliable wind/solar energy, governments try to get away with as few reliable power plants online as they can. The expense and distraction of accommodating unreliable wind/solar energy takes away money and focus from resiliency.

While we don't know yet what exactly caused certain natural gas and coal plants to go down, we know with 100% certainty that natural gas and coal plants can easily run in far more adverse conditions than what was experienced in mid-February. And we know with 100% certainty that even if no wind turbines had frozen they would have been nearly useless during large portions of the weather in mid-February.

To expose the foolishness of the idea that fossil fuels could not handle the cold temperatures in Texas, it helps to look at facts. In Texas, a spike in demand during cold temperatures led to devastating blackouts. In Alberta, Canada, a spike in demand during far colder temperatures led to very little disruption. Why? Alberta has a reliable grid with 43% coal and 49% natural gas.

If you are looking at the facts, the obvious lesson here is: stop subsidizing and mandating unreliable wind/solar energy, which are often useless when you need them most--and do a better job at managing reliable energy sources like coal, natural gas, and nuclear.

Instead of acknowledging the reality that unreliable wind/solar energy can't keep us warm or powered in the winter and that the "100% renewable" direction is disastrous, advocates of unreliable wind/solar energy are instead implying that no source of electricity can be relied upon, so no need to single out wind.

This is, of course, not correct. We know how to produce enough low-cost, reliable electricity for every situation. You build reliable power plants, including those with on-site fuel storage--such as coal and nuclear. You place a premium on reliability and resilience. That's it.

Several areas across the country, including Kansas, had an electricity crisis during bad winter weather because they did not focus enough on building reliable power plants and infrastructure. They were obsessed with getting as much unreliable wind/solar electricity as possible. Let's all learn from this mistake.

Plans to subsidize wind/solar energy should change. Biden's energy plan calls for nearly 100% solar and wind electricity by 2035! Everyone should be asking how the Biden plan would have fared in mid-February.

Kansas and America need to totally change direction in energy policy toward one of energy freedom.

APPENDIX NO. 26

Powering the Future Ensuring the Federal Policy Fully Supports Electric Reliability

POWERING THE FUTURE

ENSURING THAT FEDERAL POLICY FULLY SUPPORTS ELECTRIC RELIABILITY

U.S. SENATOR
LISA MURKOWSKI

113TH CONGRESS

AN *ENERGY 20/20* WHITE PAPER
FEBRUARY 2014

26

United States Senate

WASHINGTON, DC 20510

February 11, 2014

Dear Reader,

Just before I released my *Energy 20/20* policy blueprint last year, I chose a photo showing the Earth at night for its cover. What still strikes me as compelling about that image – and now about the cover of this document – are the lights visible from space. Concentrated heavily in developed parts of the world, and particularly here in America, those lights clearly illustrate why "energy is good" – and why federal energy policy cannot and must not be taken for granted.

If we could zoom in on individual towns and cities, those lights would tell a remarkable story about the ever-growing importance of electricity to our daily lives. For decades now, we have been accustomed to electric power on demand. We expect electricity to flow instantly, whenever we need it, for as long we need it, with only the rarest of interruptions.

All of this is made possible through the extensive series of power plants and power lines that constitute the electric grids in the "Lower 48." Although the vital importance of those systems is too often overlooked, collectively "the grid" is without doubt a sustaining source of our high standard of living and a key enabler of our national prosperity.

Over time, one of the most critical aspects of the electric grid – its reliability – has steadily improved. Today, outages on the Bulk Power System generally occur only in a handful of exceptional circumstances. Yet there are new factors and forces that are rapidly changing our energy supply mix in a manner that could fundamentally alter or degrade the system all segments of the industry have so carefully built. Among these are a mass of new environmental regulations that have contributed to the closure of many existing power plants and threaten to impact even more and, increasingly, subsidies and preferences for certain forms of power generation and use that may be leading to unintended consequences.

This white paper presents the case for greater awareness and engagement on electric reliability. Enhanced coordination between regulators and regulated entities as well as clearer voices about potentially looming problems is crucial – as are policy improvements that can and should be made by Congress.

As always, I thank you for engaging on this issue and I encourage comments on the ideas presented here and welcome the ensuing dialogue.

Sincerely,

Lisa Murkowski
United States Senator

The American Powerhouse

By and large, American electricity is American energy. Virtually all of the nation's electricity, and the vast majority of fuel used to generate it, is produced domestically. The electric power sector accounts for the lion's share – approximately 40 percent – of annual energy consumption in the United States. While the U.S. generated 4,048,000 gigawatt-hours (GWh) in 2012, it imported less than two percent of total consumption – a mere 47,000 GWh in net terms – from neighboring Canada and Mexico.[1] This stands in marked contrast to the transportation sector, which still relies on petroleum imports for a substantial share of overall consumption.[2]

Fortunately, diversity is a key characteristic of the U.S. electric system. No single source of energy provides a majority of the nation's power and each makes a distinct contribution to the nation's portfolio of electric generation resources. Coal still accounts for the overall largest source of electric generation but its use is declining. Together, natural gas and nuclear constitute roughly half of today's total net generation.[3] And renewables, both at the utility-scale and via distributed generation,[4] are adding to our resource mix at an ever-increasing rate.[5]

Geography, of course, plays a role in this diverse mix of generation resources. Illinois leads the nation in nuclear; Texas, in coal and wind; Washington, in hydropower; California, in solar.[6] West Virginia, New York, Pennsylvania, Ohio and Maryland share the abundant Marcellus Shale, an historic natural gas discovery.

The geographic diversity of our nation's resources is also highlighted by the fact that we do not have a single, unified national transmission grid. Instead, "the grid" actually comprises three separate networks of interconnected individual systems – the Western, Eastern, and Texas Interconnections – that are, in turn, integrated with one another only marginally.[7]

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[1] ENERGY INFORMATION ADMINISTRATION, MONTHLY ENERGY REVIEW (January 2014), Table 7.1 Electricity Overview. This is not to understate the significance of our bilateral trade in electricity on a day-to-day basis. In particular, the Quebec Interconnection is very important to New England electricity markets.

[2] EIA, MER (Jan. 2014), Table 7.1 Electricity Overview.

[3] Coal accounts for 37 percent of electrical generation, while natural gas accounts for a full 30 percent and nuclear for 19 percent. EIA, MER (Jan. 2014), Table 7.2a. Electricity Net Generation: Total (All Sectors).

[4] "Distributed generation" refers to energy sources, such as solar rooftop panels, located behind the retail meter or connected to a micro grid where the intent is to remove some load or demand from the system of integrated electric generation, transmission, and distribution facilities. DAVID B. RASKIN, THE REGULATORY CHALLENGE OF DISTRIBUTED GENERATION, 4 Harv. Business L. Rev. 38, 39, n.5 (2013).

[5] EIA, ANNUAL ENERGY OUTLOOK 2014 (EARLY RELEASE) 11 (2014). Hydroelectric power accounts for 6.8 percent, while biomass wood accounts for 0.9 percent, biomass waste for 0.5 percent, geothermal for 0.4 percent, solar/photovoltaic for 0.1 percent, and wind 3.5 percent. EIA, MER (Jan. 2014), Table 7.2a. Electricity Net Generation: Total (All Sectors).

[6] EIA, ELECTRICITY DATA BROWSER, *available at* http://www.eia.gov/electricity/data/browser/ (last visited Jan. 31, 2014).

[7] Nevertheless, for the convenience of the reader, this paper will refer to "the grid" in the singular. Notably, even our nation's electricity markets vary by region. However, specific electricity market issues are beyond the scope of this paper.

An Evolving Grid

A complex interaction of the power of the free market, geography, state and federal policies, and technological advancement has resulted in the modern electric grid. No other network on Earth provides as much power to as many people as reliably and affordably as the American electric grid.[8]

The Energy Mix Injected Into The Grid Is Changing

American electricity generation is always dynamic, although, until recently, change has come only slowly. The oldest operating power plants in the U.S. are hydroelectric dams, some of which were built about the time the automobile was invented.[9] As a share of net generation, coal has been "king" for decades, but its use has fallen as natural gas use has risen.[10] Over the past decade, natural gas has even surpassed nuclear power as a share of total net generation.[11] Renewables have climbed at an impressive rate, with wind power claiming the nation's largest source of new electric capacity additions in 2012.[12] In contrast, petroleum – the second most important fuel source for electricity in 1977 – has dropped to virtually zero.[13]

Looking forward, the Energy Information Administration (EIA) projects that natural gas use will increase sharply and actually surpass coal to become the dominant source of energy for electricity production by 2040. During this time period, EIA predicts a smaller but still significant increase in renewables and only a minor fluctuation in nuclear power.[14] While EIA believes coal and nuclear sources will continue to play an important role in our resource

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8 Although the affordability of electric service is largely beyond the scope of this paper, it is very nearly as crucial to our national
well-being as electric reliability. The questions of reliability and affordability are inescapably intertwined. And at present, the
opportunities for comparably reliable and affordable electric service without a grid connection are extremely rare if not
practically non-existent, in contrast to the situation in telecommunications today where wireless networks provide an alternative
to wireline. The goal should be that America has energy, taken together, that is abundant, affordable, clean, diverse and secure.
See LISA MURKOWSKI, ENERGY 20/20: A VISION FOR AMERICA'S ENERGY FUTURE 4-5 (Feb. 4, 2013).

9 Today's hydropower industry undertakes well-planned measures to protect the environment in which it operates through
voluntary efforts and via the licensing process. In 2012, hydropower accounted for almost 7 percent of total net generation and 56
percent of renewable generation. EIA, MER (Jan. 2014), Table 7.2a Electricity Net Generation: Total (All Sectors).

10 Total net electricity generated from coal dropped from 48.2 percent to 37.4 percent between 2008 and 2012. *Id.*

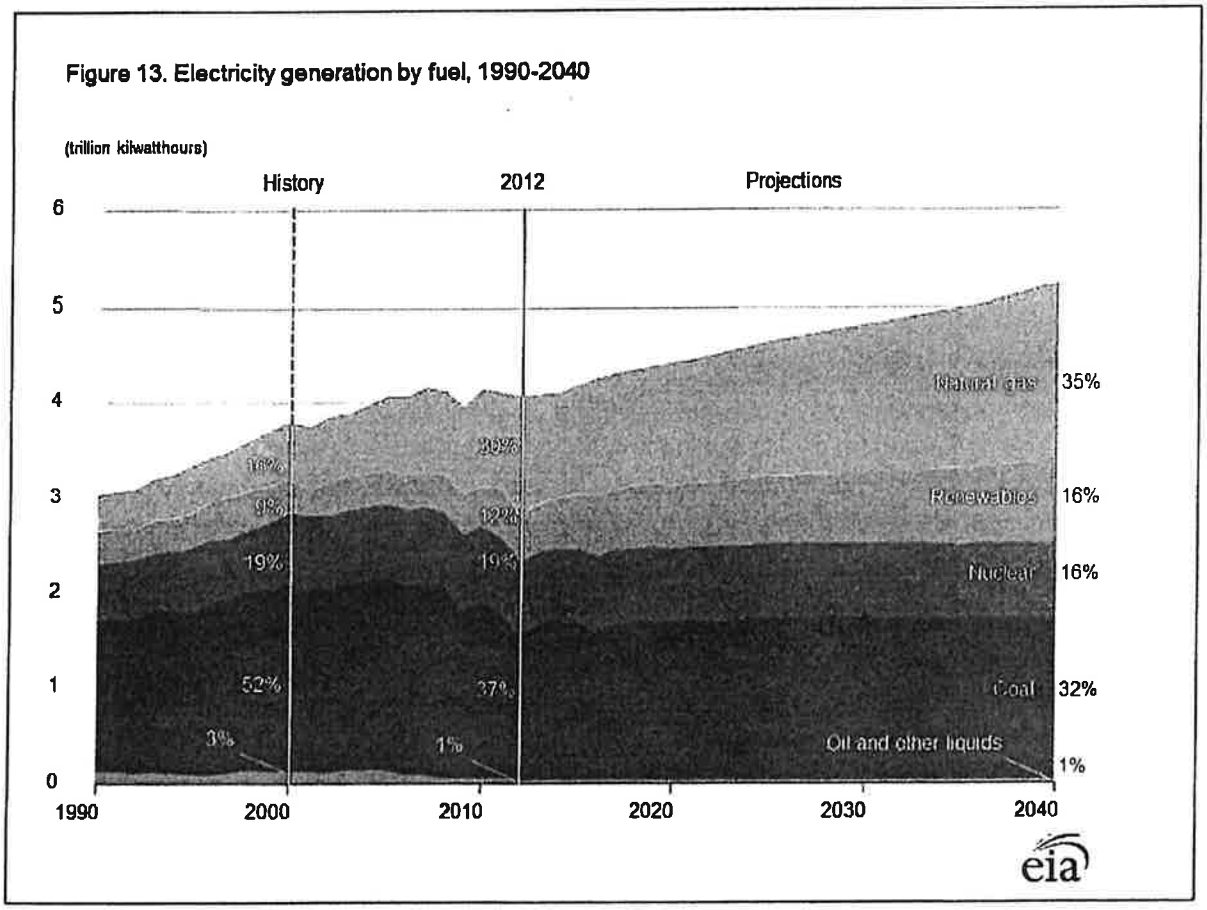
11 *Id.*

12 With 13.1 gigawatts of new capacity added in 2012, U.S. wind power installations were more than 90 percent higher than in
2011. Today wind power represents over 60,000 megawatts of capacity. DEPARTMENT OF ENERGY, WIND TECHNOLOGIES MARKET
REPORT iv, 3 (2013). *See also* AMERICAN WIND ENERGY ASSOCIATION, U.S. WIND INDUSTRY SECOND QUARTER MARKET REPORT
2013 (2013). Still, it should be noted that installed capacity is not commensurate with electricity produced. Wind power in
particular has a wide discrepancy due to multiple factors, including intermittency. The average wind capacity factor is only 31.8
percent. EIA, 2012 DECEMBER EIA-923 MONTHLY TIME SERIES FILE (2012).

13 EIA, MER (Jan. 2014), Table 7.2a Electricity Net Generation: Total (All Sectors). Even this small share can be important when
systems must operate at peak. For example, New England relied significantly on oil for electricity generation during the recent
polar vortex weather system. VAMSI CHADALAVADA, INDEPENDENT SYSTEM OPERATOR NEW ENGLAND, THE NEW ENGLAND
POWER POOL PARTICIPANTS COMMITTEE REPORT 12-20 (Feb. 6, 2014) *available at* http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/feb72014/coo_report_feb_2014.pdf (last visited Feb. 6,
2014). Also, rural Alaska continues to generate electricity by burning diesel fuel (that is barged or flown in) because it is not
economical to run transmission lines over the large distances between small communities of fewer than 500 residents.

14 EIA, ANNUAL ENERGY OUTLOOK 2014 (EARLY RELEASE) 14-15 (2014).

portfolio, these projections are always subject to change – particularly as new federal rules and regulations are issued.[15]



Source: EIA, Annual Energy Outlook 2014 (Early Release)

Natural Gas Is Taking A More Prominent Role

With natural gas production in the U.S. at record levels, resource base estimates continue to increase nearly every time they are reassessed. This has, in turn, led to a steep decline in domestic natural gas prices since 2008.[16] Natural gas has dominated new capacity additions over the past 20 years. From 2001 to 2010, nearly 150 coal-fired generators were retired in net terms, while over the same period more than 1,000 gas-fired generators came on-line in net terms.[17]

The prospect of natural gas as an affordable and, as a practical matter, abundant source of electricity on par with coal over the long-term could be leading many players in the electric power sector to shift to natural gas. Nevertheless, long-term price stability could remain a

[15] EIA's projections do not take into account the potential impact of future regulations on new plant builds or retirements.
[16] EIA, NATURAL GAS PRICES *available at* http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm (last visited Jan. 31, 2014).
[17] EIA, ELECTRIC POWER ANNUAL (2001-2010), Tables 1.5 and 2.6, Capacity Additions, Retirements and Changes by Energy Source. According to EIA, most coal-fired power plants are more than 30 years old.

challenge for natural gas.[18] The Congressional Research Service recently asserted that "fuel cost to generate electricity is the key in the decision to switch from coal to natural gas generation" and also pointed out that "a recent drop in natural gas prices has been enabled by increasing supplies . . . If the production can be sustained . . . then a long term relatively inexpensive supply of natural gas could result."[19] Fuel cost is not the only variable in the equation but it is undoubtedly a significant market factor. The extent of this so-called "structural shift" is the subject of much debate in the industry.

In any case, while certainly welcomed for its significant economic benefits, natural gas as a fuel for electric generation presents its own challenges. Greater coordination and analysis is needed to better understand and plan for the increasing role that natural gas will play in the power sector. Gas is now performing more of a hybrid role – providing peaking and baseload power and helping to smooth out intermittent resources. Gas storage capacity is improving with compressed natural gas and liquefied natural gas but large quantities of gas storage are and will continue to be required for electric generation. Additionally, new sources of gas supply and increasing use of gas for power generation could require a physically more robust gas pipeline network, as well as firmer, longer-term contracting to assure the levels of electric reliability that are increasingly expected if not required.[20] Even more fundamentally, both gas and electric supply and delivery systems will need to take gas demand attributable to electric generation into account to a greater extent than today.[21]

The Continued Loss Of Coal Capacity

A number of federal regulations proposed and promulgated by the Environmental Protection Agency (EPA) are widely expected to result in legal challenges and further coal plant retirements.[22] In practical terms, an EPA rule has the effect of capping power plant emissions at

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[18] Volatile gas prices this winter led the PJM Interconnection and the New York Independent System Operator to seek temporary relief from FERC for their $1,000 per MWh price cap; FERC granted both requests. 146 FERC ¶ 61,041 (2014) (PJM); 146 FERC ¶ 61,061 (NY-ISO). PJM is now seeking from FERC a price cap waiver through March 31, 2014, the rest of the winter heating season. *See* PJM INTERCONNECTION, ANSWER OF THE PJM INTERCONNECTION TO COMMENTS AND PROTESTS (FERC Docket No. ER14-1145) *available at* http://www.pjm.com/~/media/documents/ferc/2014-filings/20140203-er14-1145-000.ashx (last visited Feb. 10, 2014).

[19] RICHARD CAMPBELL ET AL., CONGRESSIONAL RESEARCH SERVICE, PROSPECTS FOR COAL IN ELECTRIC POWER AND INDUSTRY 5 (2013). According to CRS, natural gas prices for electric power generation overall have been relatively low since about 2009-2010 but increasing demand for power generation use may cause upward pressure on natural gas prices, particularly if there is a significant lag between this demand and new production. Also, more natural gas power generation may require new infrastructure.

[20] "Ultimately, the challenges we face with gas and electric coordination is a good problem to deal with as it's partially the result of abundant domestic gas resources. But the challenges are serious, very real, and somewhat urgent, especially in New England and the Midwest." *American Energy Security and Innovation: The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges*, House Subcommittee on Energy and Power of the Committee on Energy and Commerce, 113th Cong. (Mar. 19, 2013) (statement of Philip Moeller, Commissioner, FERC).

[21] *See* PHILIP MOELLER, REQUEST FOR COMMENTS OF COMMISSIONER MOELLER ON COORDINATION BETWEEN THE NATURAL GAS AND ELECTRICITY MARKETS (Feb. 3, 2012); *see also* FERC, GAS-ELECTRIC COORDINATION QUARTERLY REPORT TO THE COMMISSION (Sept. 19, 2013).

[22] For example, just last month the State of Nebraska filed suit against the EPA, claiming the EPA's recently proposed greenhouse gas new source performance standards for power plants violates the Energy Policy Act of 2005. Nebraska is challenging EPA's reliance on carbon capture and sequestration projects as "adequately demonstrated." *State of Nebraska v. United States Environmental Protection Agency*, Case No. 4:14-cv-3006.

fixed levels for particular pollutants by a certain point in time. The cost to comply with these rules can be very significant, as compliance may require retrofitting, the purchase of new technology (if such technology is even commercially available),[23] costly downtime for installation, and mandatory upgrades to existing infrastructure – all of which can be exacerbated by the limited availability of skilled labor and necessary equipment.

Broadly speaking, EPA rules, in effect, target older coal power plants, although some rules will clearly impact the construction of new coal power plants.[24] In terms of new plant construction, federal regulations can tip – and are now tipping – a multitude of investment decisions from one generating resource to another. For existing plants, when the owner determines that new regulatory compliance costs have rendered the facility uneconomic, then it will simply seek to retire the plant. Some units will, however, be deemed "must run" for reliability purposes. That is, the grid operators may not allow a plant to be retired if they determine that the loss of that baseload capacity could cause grid instability or lead to power disruptions. Indeed, PJM Interconnection, the Regional Transmission Organization tasked with ensuring adequate electricity supply for 61 million people in 13 states plus the District of Columbia, has refused to allow the closure of three coal plants in Ohio, deeming the 885 MW of power generated by these plants as essential for electric reliability.[25]

The Rise Of Renewables

Various state and federal policies, such as renewable energy requirements and financial incentives such as grants and tax credits[26] have caused or compelled a significant deployment of intermittent energy resources at the utility level and, at an increasing rate, the customer level. For example, with 13.1 gigawatts of new capacity added in 2012, U.S. wind power installations were more than 90 percent higher than in 2011.[27] Today, wind power constitutes over 60,000 megawatts of capacity,[28] representing a 1,347 percent increase from 2001.[29] And with 9,177

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[23] Kevin Holewinski & Daniella Einik, EPA'S PROPOSED NEW SOURCE CLEAN AIR ACT STANDARDS AND CARBON CAPTURE AND STORAGE TECHNOLOGY *available at* http://www.lexology.com/library/detail.aspx?g=b31efb54-741d-472c-912a-8e83465dbbf7 (last visited Feb. 4, 2014).

[24] Environmental Protection Agency, *Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units* 79 Fed. Reg. 1,430 (proposed Sept. 20, 2013) (to be codified at 40 C.F.R. pt. 60).

[25] In 2012, First Energy Corp. scheduled closure of three Ohio coal plants rendered uneconomic by the EPA Mercury Air Toxics Standards (MATS), which takes effect in 2015. The grid operator, PJM Interconnection, LLC, deemed the 885 MW of power generated by these plants essential for electric reliability. PJM, ZONAL COST ALLOCATION FOR RETAINING ASHTABULA 5, EAST LAKE 1-3 AND LAKE SHORE 18 GENERATORS *available at* http://www.pjm.com/~/media/planning/gen-retire/2012-2015-zonal-cost-allocation-for-retaining-ashtabula-east-lake-and-lake-shore-generators.ashx (PJM states there will be reliability issues without these plants). PJM entered a "must run" agreement with First Energy to keep the grid stable. JIGNASA GADANI, OFFICE OF ENERGY MARKET REGULATION, FERC (2013) *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13155277 (last visited Feb. 10, 2014) (FERC letter accepting rates under reliability must run agreement). At a FERC Technical Conference convened to discuss electric reliability, Midwest Independent Transmission System Operator commented, "Reliability in the Midwest will be severely challenged throughout the implementation period of the proposed [EPA] rules…In order for MISO to meet its reliability obligations, generator outage requests will be denied in order to maintain adequate supplies." *See* MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, COMMENTS OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, FERC Reliability Technical Conference Docket No. AD12-1-000, 2 (November 22, 2011).

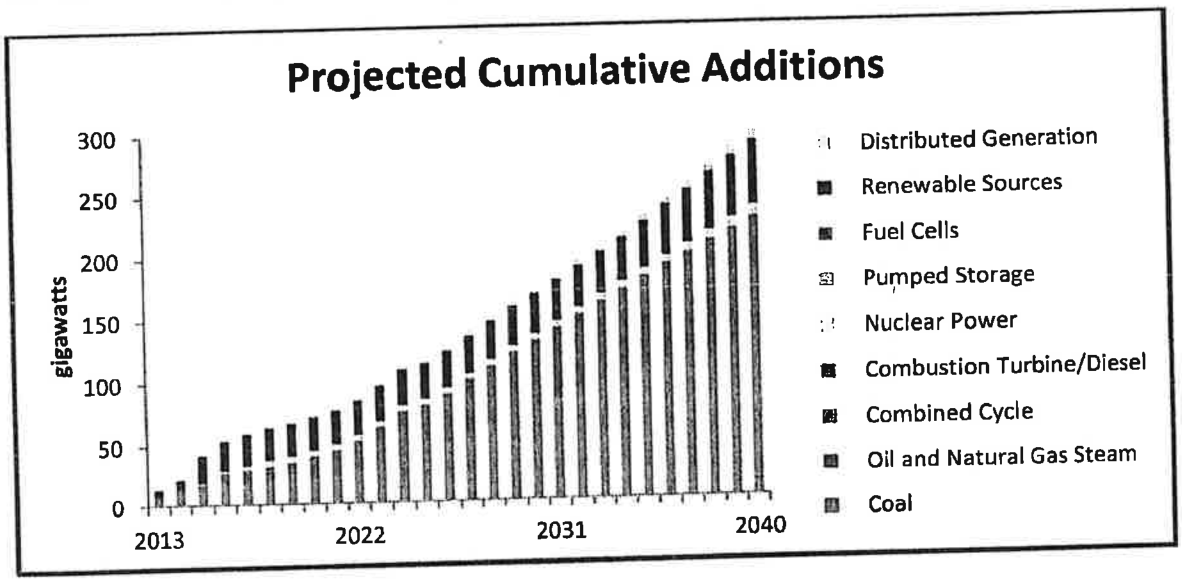
[26] The federal production tax credit expired on December 31, 2013.

[27] DOE, WIND TECHNOLOGIES MARKET REPORT iv (August 2013).

[28] *Id.* at 3.

megawatts installed, solar power capacity in the U.S. has made dramatic gains as well, increasing by 93 percent from 2011 to 2012.[30]

Innovation and new technology are American strengths that deserve encouragement. For example, we should continue to fund basic energy research and development. It is well known that deployment of a new technology such as distributed solar can face hurdles, especially in network industries. Understandably, however, whether and to what extent government should intervene to encourage technology deployment is a hotly debated question. Thus it is no surprise that questions surrounding deployment of distributed resources have presented some controversy. In the best case, competition in deployment and use between established and emerging technologies would occur based upon the merits of the technologies themselves. Where public policies intervene, the policy challenge, especially during a transitional period, is to balance competing issues. For the electric grid, reliability and affordability must remain the core considerations, and no electric generation resource should be the victim or the beneficiary of undue discrimination.



Source: EIA, Annual Energy Outlook 2014 (Early Release)

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[29] AMERICAN WIND ENERGY ASSOCIATION, U.S. WIND INDUSTRY SECOND QUARTER MARKET REPORT 2013 – AWEA MEMBER VERSION 4 (2013) *available at* http://awea.files.cms-plus.com/FileDownloads/pdfs/AWEA2Q2013WindEnergyIndustryMarketReport_Executive%20Summary.pdf (last visited Feb. 4, 2014).

[30] Approximately 91 percent of installed solar capacity is solar photovoltaic. Data compiled by EIA staff. EIA, ELECTRIC POWER MONTHLY (Jan. 2014), Table 6.2B *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_02_b (last visited Feb. 6, 2014). EIA, FORM EIA-860 DETAILED DATA (Jan. 2014) *available at* http://www.eia.gov/electricity/data/eia860/xls/eia8602012.zip (2012) and http://www.eia.gov/electricity/data/eia860/xls/eia8602011.zip (2011) (last visited Feb. 6, 2014). EIA, NOVEMBER 2013 EIA-860M (Jan. 2014) *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_01 (last visited Feb. 6, 2014). EIA, ELECTRIC POWER SALES, REVENUE, AND ENERGY EFFICIENCY FORM EIA-861 DETAILED DATA FILES (Jan. 2014) *available at* http://www.eia.gov/electricity/data/eia861/zip/f8612012.zip (2012) and http://www.eia.gov/electricity/data/eia861/zip/f86111.zip (2011) (last visited Feb. 6, 2014). EPA, FORM EIA-826 DETAILED DATA (Jan. 2014) *available at* http://www.eia.gov/electricity/data/eia826/xls/f8262013.xls (last visited Feb. 6, 2014).

The Critical Issue Of Electric Reliability

Federal policy debates surrounding energy generally, and to some extent electricity specifically, have tended in recent years to emphasize production, with industry participants, other stakeholders, and public officials arguing in support of their favored resource. This is the so-called "upstream" side of the equation. As important as energy production, however, is its conversion into a usable form and its transportation. Of further importance is the capacity to transmit that energy "downstream" continuously without interruption, particularly during hours of peak demand when its consumption may be most vital.

In stark contrast to far too many around the globe suffering in energy poverty with limited or no access to electricity, for most Americans the light turns on when they flip the switch.[31] Keeping the lights on, however, is a highly complex undertaking, requiring extensive planning and coordination. The lack of few efficient and commercially viable large-scale electricity storage mechanisms becomes more important as the energy resource mix changes and requires an electric grid that is both flexible and resilient. This is especially true when baseload generation is taken offline and grid fundamentals change.

The Grid Was Designed For An Earlier Supply Mix

Conventional wisdom would have us believe that the injection of more electricity onto the grid, regardless of duration, is always a good thing, but our grid operators can attest to the reality of today's situation. Instead of relying only on controllable and dispatchable units to meet demand, grid operators are grappling with intermittent resources that run only when the wind blows or the sun shines, along with distributed generation units that permit customers not only to receive electricity but also to transmit power back onto the system.[32] These resources introduce greater variability into the grid in contrast to the traditional situation where baseload plants predominately provide power to the grid on a consistent and predictable basis. With the increased penetration of renewables, our grid managers are now forced to back-off and cycle down baseload generation.[33] Not only is this constant ramping putting more stress on generating assets, it is forcing our grid to operate in a way for which it was not designed. These transformative changes require an even closer consideration of ancillary services, such as voltage control and frequency response, that are necessary to maintain grid reliability.

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[31] Approximately 1.3 billion people in developing countries have no access to electricity and 2 billion have only limited access. CHARLES EBINGER & JOHN BANKS, THE ELECTRICITY REVOLUTION 5 (2013).

[32] One of the potential benefits of distributed generation can be to stave off the need to build new transmission. However, it is important to recognize that it is changing the way the existing grid must operate. In *The Electricity Revolution*, the authors note that distributed generation is giving rise to what some are dubbing "prosumers" where end-use customers are becoming both producers and consumers of electricity. EBINGER & BANKS at 4. Prosumers often call on net metering policies in approximately 40 states that allow retail customers, including commercial and industrial customers, to offset their electricity purchases from the grid with energy generated behind the retail meter, such as rooftop solar panels. Net metering is valued at the bundled retail rate for electricity which does not include grid-related costs and may allow owners of distributed generation to sell their energy at two to six times the wholesale market price for energy. RASKIN at 40-41.

[33] NERC & CALIFORNIA INDEPENDENT SYSTEM OPERATOR, 2013 SPECIAL RELIABILITY ASSESSMENT 14 (2013); *accord* N. KUMAR ET AL., NATIONAL RENEWABLE ENERGY LABORATORY, POWER PLANT CYCLING COSTS iv (2012).

Electric customers and even policymakers can take ancillary services for granted but these services are crucial. For example, voltage collapse – a failure of voltage control – has significantly contributed to several major blackouts.[34] In a sense, we have been warned by these earlier events. The nation's Electric Reliability Organization (ERO), the North American Electric Reliability Corporation (NERC), identifies additional ancillary services and ramping capability as key drivers for incorporating these new, alternative resources to the grid.[35] Moreover, who pays for these services, as well as the transmission needed to connect intermittent resources to the grid, is a key policy question. Finally, as distributed generation grows, NERC assesses that with a "significant amount of DERs [Distributed Energy Resources] online, the inability to remain interconnected, stable, and functional during and after a system disturbance presents a significant risk to the BPS [Bulk Power System]."[36]

Will Today's Grid Be Less Reliable Than Even Two Years Ago?

Generally we have a healthy and effective national electric grid, but on occasion demands on the system or damage to it will outstrip the grid's ability to respond. Outages can be caused by weather, criminal activity (both physical and cyber-related), human error, fires, lightning, and other events. According to NERC, the grid experienced just three so-called "high-stress days" in 2012. All three occurred in the Eastern Interconnection and were caused directly by Superstorm Sandy and the derecho that impacted Midwest and Mid-Atlantic states.[37]

The Bulk Power System (BPS) has already been challenged in 2014. The deep freeze brought on by January's polar vortex resulted in at least 50,000 megawatts of power plant outages.[38] The electric industry has an impressive history of learning and improving from these system challenges. Among other things, what we learned from the Polar Vortex is that for one key system 89 percent of the coal capacity that is slated for retirement next year was called upon to meet demand.[39] We also learned that nuclear power plants operated at over 90 percent capacity

[34] Voltage collapse occurs when an increase in load or loss of generation or transmission facilities causes voltage to drop, which causes a further reduction in reactive power from capacitors and line charging, and still further voltage reductions. If the declines continue, these voltage reductions cause additional elements to trip, leading to further reduction in voltage and loss of load. *See* NERC STEERING GROUP, TECHNICAL ANALYSIS OF THE AUGUST 14, 2003 BLACKOUT *available at* http://nerc.com/docs/docs/blackout/NERC_Final_Blackout_REort_07_13-04.pdf (last visited Feb. 4, 2014); *see* NATURAL RESOURCES CANADA & US DEPARTMENT OF ENERGY, FINAL REPORT ON THE IMPLEMENTATION OF THE TASK FORCE RECOMMENDATIONS 17-19 (addressing the "direct causes of the August 14, 2003 blackout"), 29-31, 34-35 (2006); *see also* Richard Pérez-Peña & Eric Lipton, *Elusive Force May Lie At Root of Blackout*, N.Y. TIMES, Sept. 23, 2003 at A20.

[35] NERC, LONG TERM RELIABILITY ASSESSMENT 2013 25 (2013). The Energy Policy Act of 2005 (2005 Act) placed the primary regulatory responsibility for reliability with the Electric Reliability Organization (ERO) designated by FERC. As expected when the 2005 Act became law, FERC designated the North American Electric Reliability Corporation (NERC) as ERO.

[36] *Id.* at 26. In a joint report, NERC and CAISO warn that "[i]f variable energy generators are developed on a large scale at the distribution system level, then any impact of this penetration on the transmission system will need to be analyzed. A large majority of DERs are not visible to BPS operators." NERC & CALIFORNIA INDEPENDENT SYSTEM OPERATOR at 23.

[37] NERC, STATE OF RELIABILITY 2013 6 (2013).

[38] FERC, FERC STAFF UPDATES COMMISSION ON RECENT WEATHER EFFECTS ON THE BULK POWER SYSTEM 12 (2014) *available at* http://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf (last visited Feb. 10, 2014).

[39] Nick Akin, *Fourth Quarter 2013 Earnings Webcast of American Electric Power* (Jan. 27, 2014) (6:11-7:08) http://www.aep.com/investors/eventspresentationsandwebcasts/imageviewer/default_stretchy.htm?show=small#.

through the event, demonstrating their consistency, resiliency, and reliability.[40] This should serve as a wake-up call to the continued importance of baseload capacity.

Over the long-term, the large number of forecasted coal and nuclear baseload plant retirements[41] has led some analysts to speculate that the grid may be unable to function as reliably as it did in 2012.[42] Replacing this retiring baseload capacity, while managing an increasingly variable energy mix is the central challenge of electric reliability in the coming decades.[43] Instead of promoting even greater reliability and fuel diversity, however, government policies are instead creating challenges for baseload generation.

Retirement Math

Will The Federal Government Get A Failing Grade?

Notably, net summer capacity for domestic coal power plants stood at approximately 315 gigawatts in 2011.[44] Simple arithmetic reveals a significant problem that industry, government regulators, and Congress must pay attention to and address. Numerous analyses have been conducted on the retirement math by the experts and the results are noteworthy if not alarming. According to the EIA, nearly 27 gigawatts of coal-fired capacity is planned to retire during the 2012 to 2016 period.[45] More than nine gigawatts were retired in 2012 alone.[46] The EIA also projects in its annual reference case that nearly 50 gigawatts of this baseload capacity may retire by 2020.[47] The National Renewable Energy Laboratory predicts 33 gigawatts of coal retirements through 2026, while industry estimates range as high as 73 gigawatts through 2025.[48] These estimates align with the Government Accountability Office's (GAO) analysis, which found an additional 15.7 to 25.2 gigawatts of capacity may be retired through 2020 on top of the 30.4

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[40] US NUCLEAR REGULATORY COMMISSION, POWER REACTOR STATUS REPORTS (2014) *available at* http://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/2014/ (last visited Feb. 6, 2014).

[41] Just last year four nuclear reactors were closed, and a fifth unit is scheduled to shutdown in 2014. Two of these facilities, the Kewaunee plant in Wisconsin and the Vermont Yankee plant in Vermont, cited economic reasons as the basis for their closures even though the facilities received license renewals. Financing options are limited for new nuclear power and high construction costs are viewed as one of the stumbling blocks to more extensive nuclear development. For example, the Vogtle units in Georgia are estimated to cost $13.5 billion and the Summer units in South Carolina are estimated to cost $11.6 billion. MARK HOLT, CONGRESSIONAL RESEARCH SERVICE, NUCLEAR ENERGY POLICY 3-6 (2013).

[42] CENTER FOR STRATEGIC AND INTERNATIONAL STUDIES, RESTORING US LEADERSHIP IN NUCLEAR ENERGY 27 (2013) ("In many parts of the country, nuclear plants anchor the electric grid and help to assure the continuous, reliable availability of affordable, high-quality electricity services on which our economy – and our defense systems – depend. As these plants retire, large quantities of new baseload capacity will be needed to assure continued grid stability.")

[43] Satisfying new demand from population and economic growth can also challenge reliability but EIA predicts that electricity demand will increase by less than 1 percent per year by 2040. EIA, ANNUAL ENERGY OUTLOOK 2014 (EARLY RELEASE) 14 (2014).

[44] EIA, Annual Energy Review 2011 Table 8.11b Electric Net Summer Capacity: Electric Power Sector, 1949-2011 (2012) *available at* http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0811b (last visited Feb. 5, 2014).

[45] EIA, TODAY IN ENERGY: 27 GIGAWATTS OF COAL-FIRED CAPACITY TO RETIRE OVER NEXT FIVE YEARS *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=7290 (last visited Feb. 4, 2014).

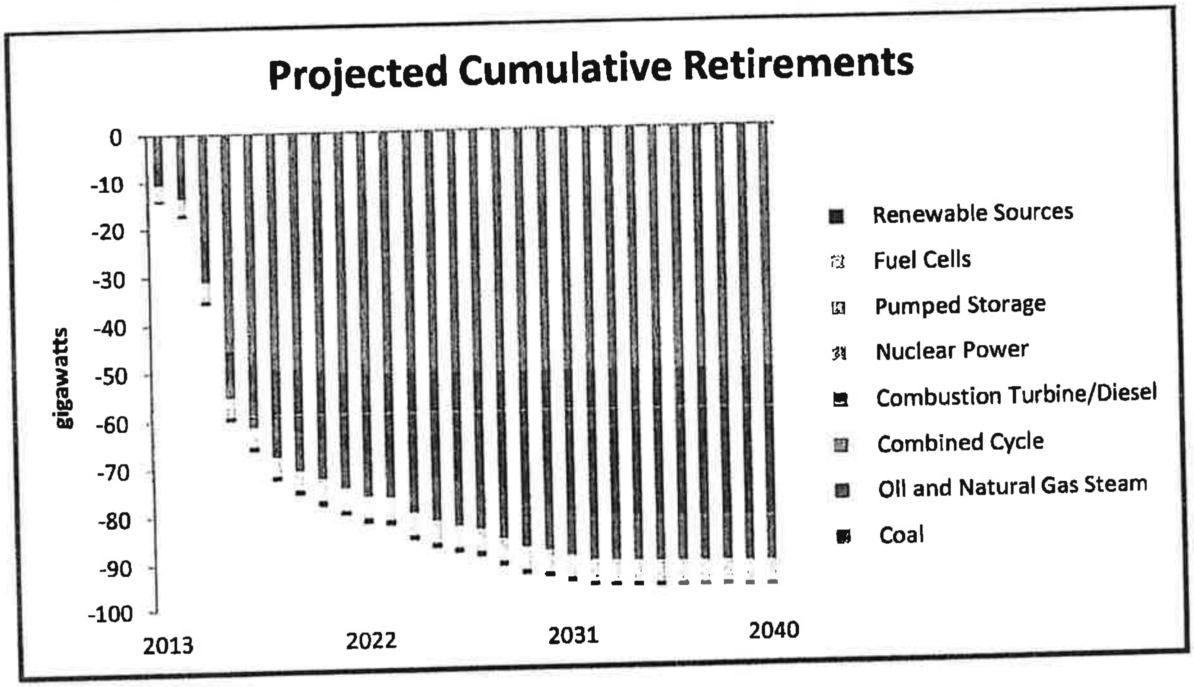
[46] *U.S. coal-fired power plant retirements top 9,000 MW in 2012*, REUTERS, July 27, 2012 *available at* http://www.reuters.com/article/2013/01/04/utilities-coal-usa-idUSL1E9C352P20130104 (last visited Feb. 4, 2014).

[47] EIA, AEO 2014 (EARLY RELEASE) Table A9 Electricity generating capacity (2014) *available at* http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014ER&subject=0-AEO2014ER&table=9-AEO2014ER&region=0-0&cases=full2013-d102312a,ref2014er-d102413a (last visited Feb. 4, 2014).

[48] EIA, ANNUAL ENERGY OUTLOOK 2013 99. *See also* ICF INCORPORATED, CURRENT STATE AND FUTURE DIRECTION OF COAL-FIRED POWER IN THE EASTERN INTERCONNECTION (2013).

gigawatts that are already slated for retirement.[49] NERC experts have determined that coal plant peak generation will decline substantially, with a net reduction of 35.1 gigawatts by 2023.[50] Notably, as more plant retirement data has become available, NERC projections have risen substantially since 2012, more than doubling its prior projection of 16.3 gigawatts in anticipated retirements.[51]

Estimates obviously vary and the market is not static, but these numbers indicate that approximately 10 to 20 percent of existing coal capacity could be retired by the middle of the next decade. This deficit will have to be met, according to the projections, by more natural gas and renewable generation. It remains to be seen whether those resources, coupled with greater reliance on end-use consumer behavior for demand response efforts and other energy efficiency measures, will rise to meet that deficit quickly enough.



Source: EIA, Annual Energy Outlook 2014 (Early Release)

[49] GOVERNMENT ACCOUNTABILITY OFFICE, SIGNIFICANT CHANGES ARE EXPECTED IN COAL-FUELED GENERATION, BUT COAL IS LIKELY TO REMAIN A KEY FUEL SOURCE 17 (2012).

[50] NERC, LONG TERM RELIABILITY ASSESSMENT 2013 at 10-11. For fossil-fuel plants generally, NERC accounts for 25 GW retirements since 2012, and estimates retirements to continue for 10 years largely in response to the confluence of final and potential environmental regulations, low natural gas prices and other economic factors. *Id.* at 3. NERC estimates that 85 gigawatts of fossil-fired retirements will occur by 2023. *Id.* Additionally, in 2010, experts at the Federal Energy Regulatory Commission (FERC) conducted an "informal, preliminary assessment" that, while heavily caveated and based only on an incomplete picture, concluded that 81 gigawatts of coal-fired generation was either "likely" or "very likely" to retire. Although dismissed by the then FERC Chairman as a "back of the envelope" calculation at the time, the Chairman elected not to conduct a formal assessment. *The American Energy Initiative (Day 12): The Impacts of the Environmental Protection Agency's New and Proposed Power Sector Regulations on Electric Reliability*, House Subcommittee on Energy and Power of the Committee on Energy and Commerce, 112th Cong. (Sept. 14, 2011) (statement of Jon Wellinghoff, Chairman, FERC); *see also Senator Murkowski's Questions to FERC, EPA on Electric Reliability* (2011) *available at* http://www.energy.senate.gov/public/index.cfm/2011/8/ii-e4a227e1-9ec8-4b24-ad3a-1fc0d9c28462 (last visited Feb. 5, 2014).

[51] NERC, LONG TERM RELIABILITY ASSESSMENT 2013 at 10-11.

Federal Regulations Should Not Be Proposed In A Vacuum

Although it is difficult to disaggregate precisely how many of the projected coal retirements are due to environmental regulations, rather than to the other broader forces described above, there are early indications. According to the GAO, "[a]vailable information indicates that existing and potential future regulations may make it more expensive to generate electricity using coal, thus affecting coal's future use."[52] Additionally, NERC recently determined that coal plant retirements will be particularly rapid between 2014 and 2016 when EPA's Mercury and Air Toxics rule becomes effective.[53]

The concern is not just one single rule, but rather it is the accretion of rules and the process by which they are unrelentingly proposed and implemented, as if in a vacuum. Multiple EPA rules will impact the utility industry; particularly, the following suite of regulations continues to draw the most attention:

1. **Cooling Water Intake 316(b)** – Stringent fish mortality and water intake velocity standards, without regard to site-specific factors, may make the standards unachievable.
2. **NAAQS Ozone** – Controversial air quality standards that have been challenged in court.
3. **NAAQS PM2.5** – Additional air quality standards based on questionable cost-benefit studies.
4. **Regional Haze** – Air quality standards designed to remove, over a forty-year time span, any pollution causing an 'impairment of visibility' in Class I areas that will potentially force any power plant emitting visible emissions to cease operation or apply as of yet undeveloped emissions control measures.
5. **GHG NSPS for New Units** – Greenhouse gas emission standards designed to support President Obama's climate change agenda will likely eliminate coal as an option for affordably meeting demand growth.
6. **GHG NSPS for Existing Units** – An expansion of greenhouse gas emission standards from new to existing coal plants, which could exacerbate the already steady stream of power plant retirements.
7. **Coal Ash** – Regulation of the storage and containment of coal ash, a byproduct from power plants, which could further drive up compliance costs at new and existing plants.
8. **Reconsideration of the Mercury and Air Toxics (MATS or Utility MACT) Rule** – One of the most costly and stringent regulations, EPA was forced to respond to considered and persistent concerns over reliability as the rule was in the last stages of development before being issued in December 2011.[54]

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[52] GAO, SIGNIFICANT CHANGES ARE EXPECTED IN COAL-FUELED GENERATION, BUT COAL IS LIKELY TO REMAIN A KEY FUEL SOURCE 27 (2012).
[53] NERC, LONG TERM RELIABILITY ASSESSMENT 2013 at 10-11. Note that many of the listed EPA regulations will have impacts later than 2014-2016.
[54] *See Senator Murkowski's Questions to FERC, EPA on Electric Reliability* (2011) *available at* http://www.energy.senate.gov/public/index.cfm/2011/8/ii-c4a227e1-9ec8-4b24-ad3a-1fc0d9c28462 (last visited Feb. 5, 2014). This rule is still subject to reconsideration.

EPA is statutorily required to estimate the effects of its proposed and promulgated rules. EPA estimated that MATS would result in 4.7 gigawatts of coal-fired capacity retirements by 2015.[55] EPA also projected 4.8 gigawatts of coal-fired capacity retirements by 2014 as a result of its Cross-State Air Pollution Rule, which dealt with fine particular matter.[56] The estimates described above dwarf these numbers. Direct comparisons are again difficult because EPA's projections are limited to the impact of specific rules. EPA has not sought from NERC or the Federal Energy Regulatory Commission (FERC or the Commission) an analysis examining the impact of all of its rules in concert with one another. This has left the agency's personnel with broad discretion to attribute changes to outside forces of their choosing. Yet energy analysts have consistently cited EPA regulations as a major reason for retirements of baseload capacity.[57] And even EPA has conceded one of its individual rules could result in "localized reliability effects."[58] Ultimately, the precise numbers matter far less than the magnitude of the discrepancy between EPA's numbers and nearly everyone else's.

The federal agencies have long been on notice regarding the potential consequences of EPA regulations to grid stability. In 2012, GAO warned that the relevant federal agencies – the Department of Energy, FERC, and EPA – "have not established a formal, documented process for jointly and routinely monitoring industry's progress and, absent such a process, the complexity and extent of potential reliability challenges may not be clear to these agencies."[59] The Federal Government simply cannot afford to ignore this red flag and risk failing the test of electric reliability by refusing to examine the impacts of its own policies.

The Challenge

If the retirement assessments described above are accurate in broad terms – and recent experience suggests they are – then environmental rules, federal and state policies to advance renewable energy and distributed generation, wholesale electricity market rules, and potentially other federal regulations are likely to add to the challenge the U.S. electric grid already faces to maintain reliability, let alone improve it. Although widespread and persistent BPS outages do not

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[55] EPA, REGULATORY IMPACT ANALYSIS FOR THE FINAL MERCURY AND AIR TOXICS STANDARDS 3-17 (2011). Labor unions – including the International Brotherhood of Electrical Workers and the Utility Workers Union of America – forecast that MATS alone will result in 55 gigawatts of coal plant retirements and the loss of approximately 250,000 jobs. NEWTON JONES ET AL., LETTER TO CHAIRMAN WYDEN AND RANKING MEMBER MURKOWSKI (2014) *available at* http://1.usa.gov/1b6xV2V (last visited Feb. 6, 2014).

[56] EPA, REGULATORY IMPACT ANALYSIS FOR THE FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE IN 27 STATES; CORRECTION OF SIP APPROVALS FOR 22 STATES 262 (2011).

[57] *See, e.g., U.S. coal-fired power plant retirements top 9,000 MW in 2012*, REUTERS January 4, 2013 *available at* http://www.reuters.com/article/2013/01/04/utilities-coal-usa-idUSL1E9C352P20130104 (last visited Feb. 4, 2014).

[58] In its final rule, EPA stated that "Although we do not expect to see any regional reliability problems, we acknowledge that there could be localized reliability issues in some areas – due to transmission constraints or location-specific ancillary services provided by retiring generation – if utilities and other entities with responsibility for maintaining electric reliability do not take actions to mitigate such issues in a timely fashion." EPA, *National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units* 77 Fed. Reg. 9409 (Feb. 16, 2012) (40 CFR Parts 60 and 63).

[59] GAO, BETTER MONITORING BY AGENCIES COULD STRENGTHEN EFFORTS TO ADDRESS POTENTIAL CHALLENGES 1 (2012). Note that NERC must be part of an inter-agency process.

appear to be in the offing, there is a quiet consensus that the risk of "localized" effects is growing, which may threaten reliability for a region such as a metropolitan area or a larger electric sub-region covering part of one or more states. The costs of ensuring that even "localized" effects do not occur will accumulate over time. This is especially true if other federal policy threats to baseload generation persist. And it is also true that given that the electricity flows through the grid at the speed of light, "localized" effects can too quickly spur cascading outages that cause widespread blackouts.

Federal Agencies Must Work Together And With Industry To Ensure Grid Stability

At a minimum, federal agencies with a stake in the matter, notably FERC and EPA, must communicate honestly, effectively, and in a timely and transparent manner through a formal and documented interagency process. Government agencies have a responsibility to work together to ensure that their actions do not increase the risk of electric reliability disruptions. Most important in this regard, FERC must be an unambiguous champion for reliability. The Commission is the federal agency with the ultimate statutory responsibility for reliability. EPA clearly has critical obligations with respect to air and water quality. In meeting those obligations, however, it should not pursue an industrial planning agenda to drive technology through regulation and should be required to take carefully into account the views of reliability regulators FERC and NERC.[60] Now is the time for a vigorous, candid discussion of ideas for amending the Federal Power Act to provide for a more formal interagency process to ensure the reliability of the grid and amplify the contributions that independent analysis can bring to bear.[61]

For their part, entities with the legal and commercial responsibility to keep the lights on – and these are primarily providers and transmitters of electricity – should not be circumspect about the risks that interconnected electric systems face. In the 2005 Act, Congress recognized the electric industry's important voice when it called for robust stakeholder participation in establishing mandatory reliability standards. These professionals and the organizations that employ them are less comfortable discussing the difficult topic of how government action may be increasing risks for electric reliability. Being regulated, entities within the electric industry are naturally reserved. It is plausible also that they do not want the mere discussion of risk – even for a moment – to be seen as "crying wolf" on reliability. That is certainly understandable, but the potential impact of federal regulation on electric reliability – including but not limited to environmental regulation – is a topic that we cannot ignore with the hope that it will simply go away.

[60] As the agency ultimately in charge of ensuring the nation's electric reliability, FERC should work closely with the ERO to engage fully on this issue with a formal report of the cumulative effect of government regulations on baseload capacity and the reliability of the grid.

[61] Legislation has been introduced this Congress to address portions of this problem, but policymakers need to take a broad view with the goal of preempting and mitigating reliability problems before they occur.

A Call For Action

Now is the time to gather facts concerning the impact of policies intended to promote the introduction of new generating technologies with an eye to clarifying the federal role with respect to these emerging issues. Industry, regulators, and other leaders should share their candid views more vigorously, "letting the chips fall where they may." We need greater confidence that the ongoing improvements we seek in electric system performance will be appropriately balanced. The reliability of electric service, along with its affordability and environmental performance, must be continuously maintained and improved. At a minimum, our federal government agencies must formally review and recognize the realistic and predictable consequences of their regulatory actions and Congress should conduct more regular and comprehensive oversight to establish the facts on which reforms should be based. It may also be time to consider regulatory and even legislative reforms that will ensure a more robust role for electric reliability professionals in evaluating environmental rules.

APPENDIX NO. 27

Reliable Electricity is a Cornerstone of Public Power Working for Nebraska

Reliable electricity is a cornerstone of public power

Reliable electricity is a cornerstone of public power

Reliable electric service is a luxury we often take for granted. Unfortunately, we may not think about how important a reliable energy supply is to us until we have to go without it, like during a severe storm. For Nebraska's public power providers, reliability has many components. Reliability is considered at every step of the electric delivery process, from the point of generation to delivery into our homes and businesses. Reliability can be impacted by the different generation resources used, by the age and maintenance of utility infrastructure, by security concerns, and by the ability to deploy a trained workforce to restore power in the event of an outage.

Reliability begins by choosing the best generation resource for our system needs. Nebraska's generation mix is a diversified portfolio of resources which include coal (73 percent), nuclear (17 percent), natural gas (4 percent), hydroelectric (4 percent), and renewable resources (2 percent). Each of these generation resources provides its own positive and negative attributes which can include cost considerations, environmental impact, and the availability of that resource. In

Fact.

Public power is owned and operated by the ratepayers is serves.

regards to relatability, not every resource is created equally. Base load resources like coal, nuclear, natural gas, or hydroelectric power can run continuously and can be actively controlled to follow load and meet consumer demand. Variable resources like wind and solar, however, rely on environmental conditions which can be hard to reliably predict. As wind speeds vary or cloud cover changes, the electric output from these generation resources can fluctuate dramatically and in an unpredictable manner. This complicates an already difficult load-balancing process. Unfortunately, most power plants were not built to be continuously ramped up and down. Unlike your light switch, they cannot be turned on and off at a moment's notice.

From the power plant, electricity travels at the speed of light through transmission and distribution lines to end users. What many don't know is that there is currently no economical way to store large amounts of electricity. There are no large battery systems capable of storing excess capacity for a later time when that power is needed. The moment we turn on the light switch, a generator must be running at that instant to meet that demand. This means that Nebraska's electric providers must balance the energy needs of consumers with the generation supplied. This requires a complicated balancing process which takes into account customer usage trends and weather forecasting to help predict demand. Load control centers monitor electric generation and demand at every minute of every day, relaying messages to power plants telling them to increase or decrease generation to match consumer demand. If demand exceeds the amount of generation available, blackouts could occur.

Reliable electricity is also the result of a complex infrastructure of substations, transformers, and miles of transmission and distribution lines. The electric grid must be constantly monitored, controlled, and maintained to ensure reliability. Some of the most common causes of electric outages are related to animals and trees coming into contact with power lines and weather related incidents. The electric grid has many safeguards designed to isolate these outages. Circuit breakers along the power lines will trip isolating an outage and in many cases electricity can be redirected along a secondary path keeping the lights on for customers. Electric providers have also incorporated new advances in technology which can help to pinpoint the cause of outages, decreasing the time needed to identify the source, make repairs and reenergize electric lines.

Despite all efforts to maintain electric infrastructure and provide reliable service, Nebraska's severe weather can take a toll of our electric system. In the event of an outage, rural electric member-systems work together and employ a workforce of dedicated men and women that are called into action. These individuals often work in extreme and dangerous weather conditions to ensure you continue to have electricity.

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  - Local Control
  - Reliable

Often working at night during severe storms, lineman must travel through flooded roads identifying storm damage. Once damages have been assessed and the source of an outage identified, rural electric systems have developed emergency response plans to restore service as fast as possible. This usually means that individuals work in a way that will get electricity restored to the most people as soon as possible. Major repairs involving substations and transmission lines may affect thousands of people and will need to be repaired before distribution lines and individual outages will be fixed.

Nebraska's energy experts are managing the demands of a complex electric grid while responsibly increasing the use of environmentally friendly renewable energy resources and doing so with fewer outages than our neighboring states. A reliable electric supply is a result of a complex system of multiple generation resources, miles of transmission and distribution lines, a complex load monitoring system, and a dedicated workforce willing to work in extreme conditions to keep your lights on. Nebraska's rural electric member-systems are working hard to keep your lights on and we are proud of our record.

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APPENDIX NO. 28

SPP Becomes First Regional Grid Operator with Wind as No. 1 Annual Fuel Source

January 26, 2021

SPP becomes first regional grid operator with wind as No. 1 annual fuel source, considers electric storage participation in markets, approves 2021 transmission plan

LITTLE ROCK, ARK. — Southwest Power Pool's (SPP) leadership and stakeholders met throughout January to collaborate on regional grid operations and markets, transmission planning, membership expansion and corporate affairs.

Markets and Operations
In 2020, SPP became the first regional transmission organization to have wind as the No. 1 fuel source. Wind is outpacing SPP's use of coal and natural gas.

"Maintaining reliability with this large amount of wind is extraordinary," said Barbara Sugg, president and chief executive officer. "To manage this high volume of variable energy we rely on accurate forecasting, our robust transmission system, a diverse generation mix and our equitable and efficient wholesale energy market."

The board approved three market-related studies recommended by the **2019 Holistic Integrated Tariff Team (HITT) report**. Staff analyzed dynamic line ratings, automatic mitigation of unduly low offers and offer requirements for variable resources.

SPP continues to focus on electric storage resources (ESR). A **new task force** is addressing Federal Energy Regulatory Commission (FERC) Order 2222, which requires grid operators to allow distributed energy resources, including ESR aggregations, to participate in wholesale markets. The group is meeting regularly to meet FERC's July 19 deadline to file tariff changes.

The Markets and Operations Policy Committee (MOPC) approved recommendations regarding how ESRs' duration should be addressed in transmission planning. The MOPC is updating its **ESR Steering Committee's** scope and membership to better coordinate ESR policy decisions.

SPP is on track to launch its Western Energy Imbalance Service (WEIS) market Feb. 1. "The market is on time and under budget," Sugg said. Eight utilities from the Western Interconnection will participate in the market.

Membership Growth

The majority of WEIS participants have **submitted letters of interest** regarding membership in the SPP regional transmission organization. Placing western facilities under SPP's Open Access Transmission Tariff would produce approximately $49 million in annual production cost savings for current and new members, among other benefits.

The Strategic Planning Committee initiated its **Members Forum**, open to SPP's membership, to discuss integrating new members into SPP. The forum will meet frequently in the coming months to develop proposals related to membership expansion.

Transmission Planning

The board of directors approved the 2021 SPP Transmission Expansion Plan (STEP), a comprehensive list of planned transmission projects in the SPP region for a 20-year planning horizon. According to the STEP, 81 projects estimated to cost $444 million will be constructed over the next six years in 12 states. In 2020, SPP's members completed 29 transmission system upgrades in eight states at an estimated cost of $175 million.

"Our members' investment in the transmission network allows us to provide reliable and affordable power to consumers throughout the SPP region," said Antoine Lucas, SPP vice president of engineering. "The collaboration among companies across the region to produce this plan is remarkable."

Additionally, SPP and the Midcontinent Independent System Operator have begun a joint planning effort to identify transmission solutions that will benefit both regions.

Corporate Affairs

SPP was significantly under budget in 2020, resulting in over-recovery that reduced transmission customers' 2021 rates. In 2021 SPP implemented new cost recovery process that more closely aligns administrative costs with those who utilize SPP's services.

*Meeting materials from the January meetings are posted to **SPP.org**:*

- **Board of Directors and Members Committee**
- **Joint quarterly stakeholder briefing**
- **Markets and Operations Policy Committee**
- **Regional State Committee**
- **Strategic Planning Committee**

*About SPP: Southwest Power Pool, Inc. is a regional transmission organization: a nonprofit corporation mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its members. SPP manages the electric grid across 17 central and western U.S. states and provides energy services on a contract basis to customers in both the Eastern and Western Interconnections. The company's headquarters are in Little Rock, Arkansas. Learn more at **SPP.org**.*

Derek Wingfield, 501-614-3394, dwingfield@spp.org

APPENDIX NO. 29

SPP Regional Cost Allocation Review

(RCAR II)

July 11, 2016 (71 pages)

Copy available in office of Natural

Resources Committee)

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Regional Cost Allocation Review (RCAR II)

July 11, 2016
SPP Regional Cost Allocation Review Report for RCAR II

APPENDIX NO. 30

SPP Membership Agreement

Vol. 3 (2008)

& Addendum (84+ pages)

Copy available at office of Natural Resources Committee

MEMBERSHIP AGREEMENT

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APPENDIX NO. 31

Strengthening Energy Reliability and Independence

3B

Strengthening Energy Reliability and Independence

By Governor Pete Ricketts

August 24, 2021

Governor's official photo here.

Energy reliability and independence are pillars of our country's national security. A reliable power grid has helped our nation build the world's largest economy, and our focus on developing domestic sources of energy has made our country's fleet of automobiles and airplanes less dependent on overseas oil. Earlier this year, *U.S. News and World Report* ranked Nebraska #3 nationally for power grid reliability and #8 overall in their energy category which "tracks the reliability of power grids, renewable energy consumption and the price of electricity."

We can't take this for granted. There are forces at work at the state and federal level that could undermine these strategic strengths.

February's record-cold temperatures caused widespread power outages throughout the South and Midwest, including rolling blackouts here in Nebraska. These interruptions of service are not acceptable. The United States is not a third-world country, and we need to be prepared for extreme weather events so that this doesn't happen again. This means we need to make sure we have a diverse energy mix with enough coal and nuclear power to keep our grid running during severe weather events.

Nebraska was able to power through February's arctic blast better than some other states thanks to our state's base load power plants, including our largest generation facility—Gerald Gentleman Station, a coal-fired power plant in Sutherland—and Cooper Nuclear Station, the state's only nuclear power plant. Together, these two plants provided a significant percentage of Nebraska's power supply during the winter energy emergency. These facilities are more important than ever as other states have destabilized their power grid by becoming too dependent on variable energy systems. Nuclear power plants in the Southwest Power Pool footprint were all available and generating during the event. Coal plants were the second most dependable resource. Both wind and natural gas failed to deliver during the cold snap—these energy sources were not reliably available when we needed them.

While climate activists want to abolish coal-fired plants altogether, there are smarter ways to reduce emissions while maintaining reliable, affordable electricity and creating additional skilled jobs. For example, Nebraska Public Power District has partnered with ION Clean Energy on the design of a carbon capture system for Gerald Gentleman Station, Unit 2. The carbon capture technology is capable of capturing about 90% of CO2 emissions from the Gerald Gentleman power generation unit. Innovations like this can yield cleaner energy production without shuttering reliable facilities like Gerald Gentleman station, which has the capacity to generate electricity for more than 600,000 Nebraskans.

Power grid reliability isn't the only priority at risk of being undermined by climate extremists. Nebraska is the second largest ethanol-producing state in the nation. The future of ethanol is tied to the future of oil production and combustion engines. Together, domestic production of these fuels can help make our country energy independent.

Regrettably, the Biden-Harris Administration's radical climate agenda is doing just the opposite—making us more dependent on our country's adversaries. On his first day in office, President Biden canceled the permit for Keystone XL and rejoined the Paris Agreement. With actions like these coming out of the White House, it should be no surprise that U.S. gas prices in July 2021 were up 41.8% compared to July 2020. With inflation rising and prices soaring at the pump, President Biden is now begging OPEC+ members to produce more oil. These members include Iran, Venezuela, and Russia. Dependence on these countries puts our national security at risk.

President Biden's appeal to OPEC came less than a week after he issued an executive order calling for "50 perc of all new passenger cars and light trucks" to be Electric Vehicles (EVs) by 2030. Once again, the President's action risks our national security. The People's Republic of China produces the vast majority of the rare earth minerals needed to manufacture EVs. The President's EV goal would not only make America reliant on our nation's biggest global competitor, but it would also be economically devastating to ethanol- and oil-producing states, driving away investment in innovative technology such as carbon sequestration.

Instead of looking overseas for energy, the President should focus on growing biofuels production right here in the Heartland. Ethanol saves drivers money at the pump and cleans up the environment without sacrificing performance. Nebraska has been on the forefront of demonstrating the efficiency of high-blend ethanol fuels. In March 2021, the State announced results of a research program to study the use of E30 in conventional vehicles. The results of the study clearly showed that E30 is safe and reliable to use in them. Given its proven effectiveness, there's every incentive to increase the volume of E30 in our nation's fuel supply.

Ethanol has long helped reduce emissions, and carbon sequestration technology can help the fuel deliver a lower carbon footprint. By capturing carbon dioxide at ethanol plants that produce cleaner-burning fuels such as E15 and E30, regular vehicles can achieve well-to-wheel emissions that are competitive—if not cleaner—than those involved to manufacture and charge electric vehicles. This session, I signed LB 650 into law to establish the legal and regulatory framework for the geologic storage of carbon dioxide in Nebraska. Following passage of the law, Battelle and Catahoula Resources announced a partnership to sequester carbon dioxide in Nebraska. By reducing the carbon footprint of our facilities, we will create more opportunities for our ethanol industry.

Energy independence and reliability must remain top priorities for our nation, and in some cases President Biden will have to stand up to climate activists to achieve them. If you have questions about energy, or any other topic, please contact my office at pete.ricketts@nebraska.gov or 402-471-2244. Here in Nebraska, we'll do our part to build a reliable power grid and keep our country moving with great, clean-burning biofuels.

APPENDIX NO. 32

Tab 8 Graph
Capacity Factors
Market Resources

Tab 8

Data Request:

Identify in tabular format what baseload units were operating from 2/7/21 to 2/20/21 and what their capacity factor was per day on average. So for example it is understood that Nebraska City unit 1 was down for 2 days due to a loss of vacuum, so for those days the capacity factor would be zero. Also note for example the days that Nebraska City unit 2 was down for inspections of leaking boiler tubes, i.e. capacity factor of zero for those days. So for each district identify per unit facility the capacity factor per day. So for NPPD the results would be from Cooper, Gerald Gentleman, etc would be reported. Include hydropower units in answering this question.

Submittal:

Table per utility listing daily capacity factors for each resource from 2/7/21 – 2/20/21. For resources with joint ownership/participation, the primary owner/operator submitted data for the entire resource. Data includes SPP market resources only; no behind-the-meter generation.

Resource	Fuel Type	2/7/2021	2/8/2021	2/9/2021	2/10/2021	2/11/2021	2/12/2021	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021	2/18/2021	2/19/2021	2/20/2021
Laramie River Station	Coal	62.6%	67.4%	99.3%	86.2%	89.5%	90.8%	61.9%	55.5%	60.9%	71.4%	84.4%	80.2%	71.3%	48.1%
Walter Scott, Jr. Energy Center Unit 3	Coal	95.6%	92.2%	92.1%	93.6%	86.3%	74.6%	92.1%	91.7%	90.5%	79.0%	55.8%	0.1%	0.0%	0.0%
Walter Scott, Jr. Energy Center Unit 4	Coal	89.3%	71.6%	87.1%	96.8%	96.1%	94.3%	95.5%	82.2%	81.9%	71.8%	67.1%	93.3%	80.9%	62.7%
Terry Bundy Generating Station	Gas/Oil	32.2%	45.3%	57.6%	49.8%	68.2%	43.4%	59.8%	70.2%	65.4%	70.0%	69.1%	74.4%	63.2%	36.2%
Rokeby Generation Station	Gas/Oil	2.9%	9.6%	0.0%	4.6%	2.6%	14.7%	16.2%	17.1%	36.7%	39.5%	30.9%	26.8%	7.5%	0.0%
J Street Generating Station	Gas/Oil	0.0%	0.0%	0.0%	0.0%	0.0%	10.1%	0.0%	0.0%	50.0%	90.7%	90.7%	54.7%	24.9%	0.0%
Landfill Gas	Landfill Gas	83.3%	15.6%	39.1%	22.6%	72.0%	83.3%	82.5%	82.5%	69.4%	65.1%	78.1%	77.3%	79.9%	79.9%
Western Area Power Administration	Hydro	45.1%	55.5%	58.7%	57.6%	53.7%	53.3%	45.1%	45.1%	53.3%	53.3%	45.1%	45.1%	45.1%	41.6%
Arbuckle Mountain Wind Farm	Wind	29.5%	53.1%	4.0%	0.4%	9.4%	34.8%	51.4%	62.4%	75.2%	11.3%	14.7%	64.2%	25.5%	73.1%
Buckeye I Wind Energy Center	Wind	21.0%	9.4%	4.1%	24.2%	28.4%	37.2%	22.1%	50.7%	12.3%	44.0%	5.2%	7.3%	32.4%	34.7%
Prairie Breeze II Wind Energy Center	Wind	19.6%	0.0%	2.0%	7.0%	12.5%	11.9%	14.5%	34.8%	0.2%	25.9%	23.6%	24.4%	17.4%	36.7%

Capacity factors for SPP market resources. GGS and shared wind project data included in NPPD submittal.

Omaha Public Power District
Capacity Factors

Resource	Fuel Type	MW Capacity	02/07/21	02/08/21	02/09/21	02/10/21	02/11/21	02/12/21	02/13/21	02/14/21	02/15/21	02/16/21	02/17/21	02/18/21	02/19/21	02/20/21
Nebraska City 1	Coal	654.30	96.5%	95.8%	95.8%	74.3%	2.9%	71.2%	94.5%	93.4%	92.1%	69.7%	97.1%	97.2%	90.1%	73.3%
Nebraska City 2	Coal	691.00	97.2%	96.1%	94.2%	27.5%	-2.1%	-1.8%	5.7%	57.4%	64.2%	63.7%	63.8%	64.2%	63.8%	70.1%
North Omaha 1	Natural Gas	64.80	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
North Omaha 2	Natural Gas	90.80	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%
North Omaha 3	Natural Gas	86.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
North Omaha 4	Coal	120.10	82.9%	82.6%	82.9%	82.8%	82.0%	82.2%	81.8%	81.6%	81.7%	76.6%	79.6%	79.8%	74.3%	70.4%
North Omaha 5	Coal	216.20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.5%	51.1%	75.1%	72.1%	76.2%	75.9%	71.0%	60.8%
Sarpy County #1	Natural Gas/Oil	55.40	1.5%	-0.3%	1.2%	3.4%	-0.2%	6.0%	2.4%	-0.3%	-0.3%	-0.3%	-0.1%	13.1%	2.1%	1.8%
Sarpy County #2	Natural Gas/Oil	55.90	0.8%	17.2%	-0.2%	3.4%	-0.2%	-0.3%	1.0%	-0.3%	39.5%	47.9%	50.1%	48.6%	40.9%	20.0%
Sarpy County #3	Natural Gas/Oil	107.80	-0.2%	-0.2%	-0.2%	5.8%	-0.2%	6.4%	-0.2%	-0.3%	53.3%	4.2%	-0.2%	-0.2%	-0.2%	0.8%
Sarpy County #4	Natural Gas/Oil	48.70	-0.7%	-0.5%	-0.7%	-0.6%	-0.7%	-0.6%	-0.6%	-0.6%	-0.6%	-0.6%	17.3%	98.4%	91.2%	91.6%
Sarpy County #5	Natural Gas/Oil	47.90	-0.7%	18.5%	-0.7%	3.4%	-0.7%	12.4%	29.8%	49.9%	52.5%	51.2%	22.9%	8.0%	23.6%	4.6%
Cass County #1	Natural Gas/Oil	161.70	-0.3%	-0.3%	-0.3%	-0.3%	60.5%	40.9%	83.7%	59.1%	93.1%	94.8%	91.4%	90.8%	83.0%	35.0%
Cass County #2	Natural Gas/Oil	161.10	-0.3%	-0.3%	-0.3%	-0.3%	60.7%	0.9%	85.0%	-0.3%	66.2%	56.2%	18.2%	-0.3%	87.0%	49.6%
Jones Street #1	Fuel Oil	61.20	8.0%	29.3%	0.2%	3.3%	-0.2%	5.2%	25.2%	24.7%	54.8%	40.8%	41.7%	40.5%	23.4%	-0.2%
Jones Street #2	Fuel Oil	62.20	0.2%	28.9%	0.2%	3.4%	-0.2%	7.6%	21.3%	16.5%	49.9%	40.8%	38.5%	44.2%	37.7%	6.3%
Ainsworth	Wind	10.00	12.6%	1.6%	2.7%	0.1%	2.9%	0.7%	3.4%	0.5%	11.9%	34.8%	8.0%	10.0%	3.3%	15.0%
Flat Water	Wind	60.00	15.1%	10.1%	4.3%	24.6%	33.2%	45.0%	24.6%	50.0%	23.2%	5.1%	2.6%	6.9%	45.4%	45.6%
Petersburg	Wind	40.50	17.2%	0.1%	1.0%	6.6%	12.1%	7.7%	11.8%	32.7%	0.7%	32.7%	21.7%	20.0%	13.2%	44.7%
Crofton Bluffs	Wind	13.65	7.1%	0.5%	11.4%	8.4%	9.2%	6.3%	14.9%	21.5%	2.1%	33.8%	31.1%	27.6%	22.2%	52.6%
Broken Bow I	Wind	18.00	28.8%	0.2%	1.1%	3.3%	2.9%	4.8%	8.2%	10.2%	6.4%	51.0%	8.1%	26.4%	12.8%	34.1%
Broken Bow II	Wind	43.90	32.0%	0.2%	1.0%	2.7%	3.2%	5.3%	9.4%	12.2%	7.8%	53.4%	10.0%	31.9%	13.7%	35.5%
Elkhorn Ridge	Wind	25.00	6.4%	0.2%	4.9%	3.7%	5.0%	3.7%	8.5%	12.9%	1.4%	27.3%	21.3%	20.7%	14.3%	40.4%
Elk City 1	Landfill Gas	3.00	77.0%	77.1%	77.2%	67.5%	73.7%	68.5%	71.7%	71.4%	71.4%	68.5%	67.6%	76.9%	77.0%	77.2%
Elk City 1	Landfill Gas	3.00	100.2%	100.1%	100.2%	84.2%	95.8%	87.3%	97.4%	97.0%	96.8%	91.9%	91.8%	95.5%	95.3%	95.5%
Grande-Prairie	Wind	400.00	13.3%	1.7%	9.4%	4.7%	7.8%	6.7%	13.0%	13.7%	7.9%	50.7%	22.0%	36.1%	19.2%	42.6%
Fort Calhoun Community S	Solar	5.00	2.7%	2.3%	4.7%	8.3%	7.8%	2.5%	2.2%	3.5%	5.8%	9.5%	6.1%	14.7%	19.6%	21.2%
Sholes	Wind	160.00	14.9%	0.0%	6.4%	13.0%	24.5%	18.0%	17.4%	42.0%	1.6%	20.4%	25.6%	34.8%	19.5%	40.6%
Prairie Breeze	Wind	200.60	18.1%	0.0%	2.3%	6.7%	10.1%	12.0%	13.0%	28.7%	0.0%	2.8%	6.0%	22.4%	13.2%	41.5%

NEBRASKA PUBLIC POWER DISTRICT – Operation of Baseload Units in Feb. 2021

Unit	7	8	9	10	11	12	13	14	15	16	17	18	19	20
CNS							Operating							
Gerald Gentleman Station Unit 1							Operating							
Gerald Gentleman Station Unit 2							Operating							
Sheldon Station Unit 1							Operating							
Sheldon Station Unit 2				Off-Line							Operating			

NPPD Capacity Factor
February 7 to 21, 2021

Resource Type	Unit	Capacity Factor 2/7/2021	2/8/2021	2/9/2021	2/10/2021	2/11/2021	2/12/2021	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021	2/18/2021	2/19/2021	2/20/2021
Nuclear	Cooper	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coal	Gentleman 1	96%	88%	98%	98%	98%	98%	97%	93%	98%	93%	94%	90%	86%	49%
Coal	Gentleman 2	98%	100%	100%	101%	100%	100%	98%	86%	100%	95%	96%	90%	87%	51%
Coal	Sheldon 1	96%	99%	99%	98%	98%	92%	91%	89%	93%	70%	85%	83%	75%	65%
Coal	Sheldon 2	0%	0%	0%	0%	0%	0%	0%	0%	66%	70%	92%	80%	74%	61%
Gas	Beatrice	0%	49%	50%	72%	89%	60%	60%	62%	62%	39%	63%	70%	67%	36%
Gas	Canaday	0%	0%	0%	0%	0%	0%	0%	0%	16%	28%	23%	24%	23%	11%
Oil	Hallam	14%	24%	0%	0%	0%	3%	31%	0%	19%	30%	17%	25%	1%	0%
Oil	Hebron	14%	21%	0%	0%	0%	0%	34%	34%	0%	9%	17%	32%	25%	0%
Oil	McCook	14%	24%	0%	0%	0%	0%	16%	0%	12%	7%	16%	18%	0%	0%
Wind	Ainsworth	13%	2%	3%	0%	3%	1%	3%	1%	12%	35%	8%	10%	3%	15%
Wind	Broken Bow 1	29%	0%	1%	3%	3%	5%	8%	10%	6%	51%	8%	26%	13%	34%
Wind	Broken Bow 2	31%	0%	1%	3%	3%	5%	9%	12%	8%	52%	10%	31%	13%	35%
Wind	Crofton	7%	1%	11%	8%	9%	6%	15%	21%	2%	34%	31%	28%	22%	53%
Wind	Elkhorn	6%	0%	5%	4%	5%	4%	9%	13%	1%	27%	21%	21%	14%	40%
Wind	Laredo	17%	0%	1%	5%	10%	10%	11%	28%	0%	31%	23%	23%	12%	32%
Wind	Steel Flats	31%	27%	24%	35%	52%	52%	24%	64%	28%	12%	6%	21%	49%	38%
Hydro *	Columbus 1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	15%
Hydro *	Columbus 2	0%	0%	0%	0%	0%	0%	0%	0%	6%	53%	52%	67%	75%	90%
Hydro *	Columbus 3	0%	0%	0%	0%	0%	0%	0%	0%	9%	0%	0%	0%	0%	0%
Hydro **	Kingsley	11%	12%	23%	9%	12%	12%	13%	12%	9%	8%	10%	11%	9%	6%
Hydro	North Platte 1	51%	51%	50%	52%	52%	52%	50%	55%	58%	52%	54%	52%	52%	52%
Hydro	North Platte 2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Note - at times NPPD Resources were at lower levels to provided SPP Operating Reserves and manage Transmisson flows

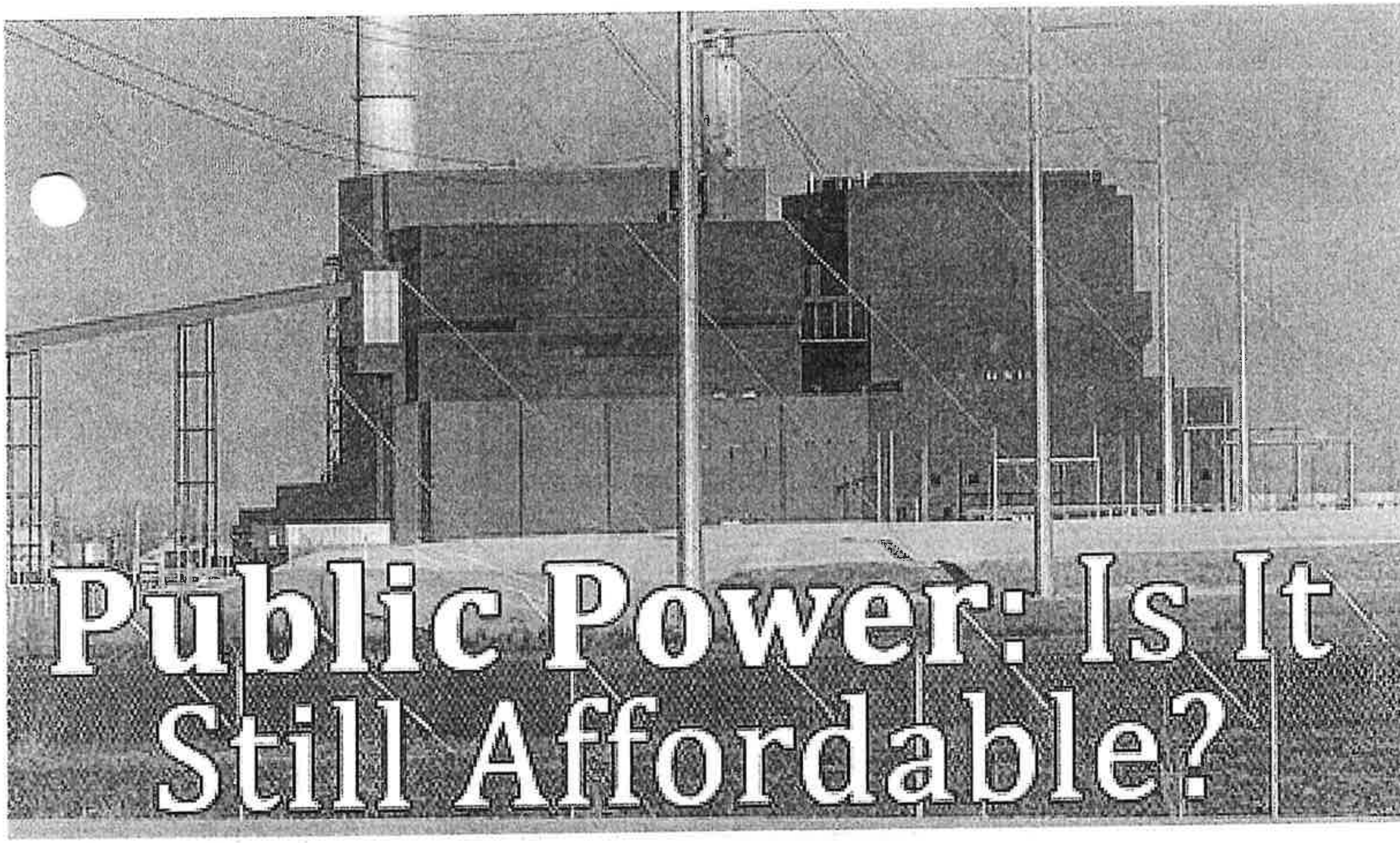
*Owned by Loup River Public Power District
**Owned by Central Nebraska Public Power District & Irrigation District

APPENDIX NO. 33

The Costs and Benefits of Public Power in Nebraska, An Investigation of Electricity Rates, Taxes, and Competitiveness

(pp 1-4)

Remainder of Report and appendices available at the office of Natural Resources Committee



Public Power: Is It Still Affordable?

Platte INSTITUTE
for economic research

The Costs and Benefits of Public Power in Nebraska: An Investigation of Electricity Rates, Taxes, and Competitiveness

Produced for the Platte Institute
for Economic Research
December 28, 2015

Ernest Goss, Ph.D., Principal Investigator
Jeffrey Milewski, Senior Research Economist
Scott Strain, Senior Research Economist

Goss & Associates

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The Costs and Benefits of Public Power in Nebraska: An Investigation of Electricity Rates, Taxes, and Competitiveness

Preface

The Costs and Benefits of Public Power in Nebraska: An Investigation of Electricity Rates, Taxes, and Competitiveness

In April of 2015, the Platte Institute for Economic Research commissioned this study. The goal of the study was to examine, analyze and report on the public power industry in the state of Nebraska to determine the cost and benefits to taxpayers, consumers, and businesses in Nebraska.

This project, while funded by the Platte Institute for Economic Research, was developed independently of this organization. Any conclusions, findings, errors or misstatements are solely the responsibility of Goss & Associates.

Goss & Associates, Economic Solutions, LLC
Principal Investigator: Ernie Goss, Ph.D.
ernieg@creighton.edu
www.ernestgoss.com
http://business.creighton.edu/economicoutlook
Creighton University, Department of Economics

Jeffrey Milewski, Senior Research Economist
jmilewski@gossandassociates.com

Scott Strain, Senior Research Economist
scott.strain@gossandassociates.com

The Goss Institute for Economic Research
600 17th Street, Suite 2800 South
Denver, Colorado 80202-5428
402.280.4757 - 303.226.5882

Goals of the study

Specific goals of the study are to:

1. Compare Nebraska's electricity rates provided relative to that supplied by private producers in other states, incorporating both direct and indirect subsidies furnished to the comparable units.
2. Investigate best practices and potential future opportunities that are, or might be, restricted under the current public power arrangements in Nebraska.
3. Establish a better understanding of the long-term implications of tax advantages provided to the public power industry and how those tax advantages affect the taxpayer and the state's overall competitive environment for consumers, taxpayers and businesses in the state.

Key Findings

The Costs and Benefits of Public Power in Nebraska: An Investigation of Electricity Rates, Taxes, and Competitiveness

I. General

- Public power companies provided electricity service to more than 2,000 communities across the nation in 2015. Supporters argue that the significant benefits of public power are due to local ownership and lower costs. Without a required profit margin, along with tax-exempt financing, which is priced at below market interest rates, public power entities are able to pass savings along to electricity consumers. In addition, public utilities are exempt from paying income and property taxes, which proponents claim also lowers rates.
- The legislative environment in Nebraska poses barriers to independent and private investment in the state. Nebraska's public power monopoly discourages private investment in new power generation because private companies are unable to enter into power purchase agreements, which would enable development.
- The cost to produce electricity in Nebraska depends considerably on the prices of fuel used in generation. Statewide, Nebraska relies heavily on coal as the primary source of fuel. Therefore, electricity rates correlate with coal prices in the market. Coal has been a relatively cheaper source of fuel for Nebraska due to the state's proximity to a large coal supply from Wyoming's Powder River Basin.
- Despite rapid declines in natural gas prices due to advanced extraction techniques, it represents less than 1.5 percent of input fuel for Nebraska electricity producers. The drop in natural gas prices has significantly lowered wholesale electricity prices, reducing the profits that Nebraska's utilities used in the past to help keep rates low. Profits generated from wholesale sales have historically helped subsidize rates for Nebraska's consumers.

II. Higher and Rapid Growth in Nebraska Electricity Prices

- Recent data show that Nebraska's electricity rates in Nebraska have grown at a much faster pace than in other states. Consequently, Nebraska no longer delivers electricity to the consumer at a rate below competitor states.
- Nebraska's overall electricity prices are projected to rise from 103.6 percent of the West North Central (WNC)[2] median in 2013 to 106.7 percent in 2018.
- Nebraska's electricity prices have grown from 96.2 percent and 67.6 percent of the 2008 regional and national medians to 103.6 percent and 95.9 percent of the 2013 medians, respectively. (Figure 1.1)
- The shutdown and recovery of the Fort Calhoun Nuclear Generating Station was a significant driver of Nebraska's rapid growth in electricity prices beyond 2011. Recommissioning ultimately cost ratepayers an estimated $177 million,[3] which is approximately 18 percent of OPPD's yearly operating expenses.[4] (Figure 5.1)

Key Findings

III. Nebraska's Volatile Electricity Prices

- Electricity price data between 2005 and 2014 show that Nebraska's volatility in overall electricity prices was the highest in the WNC region and 45.4 percent above the regional average.
- Calculations indicate that residential and industrial electricity rates for Nebraska were much more volatile than for any other state in the WNC region. Nebraska also had the greatest industrial electricity price volatility among all U.S. states.

IV. Higher Industrial Rates and Economic Development

- Nebraska's average industrial rates have trended upward over the past decade, surpassing and remaining above the national average since 2012. (Table 3.1)
- Nebraska's 2014 industrial electricity rate of 7.30 cents per kWh exceeded both the WNC median of 7.04 and the U.S. industrial rate of 7.01. (Figure 1.2)
- For 2014, Nebraska ranked in the top half of WNC states in terms of overall competitiveness of its residential rates, but in the bottom half in commercial and industrial rates. Only North Dakota and Kansas have industrial electricity rates higher than Nebraska. (Table 2.1).
- From 2005 to 2014, Nebraska had the second highest annual growth in industrial electricity rates in the region with an annual growth more than double that of the nation. Additionally, Nebraska had the greatest industrial electricity price volatility among all comparison WNC states and the median U.S. state. (Table 3.2)
    - o This is a consideration for economic development because it renders Nebraska a less attractive state for industrial growth, and is contrary to optimum electricity pricing strategies.
    - o Nebraska's climbing industrial rate has restrained the state's economic growth.[5] (Figure 3.1)
    - o Energy costs are a sizeable business and farm expense. As such, the state's industrial rate influences the profitability of firms and incentivizes them to invest, locate and expand in area with lower rates.
        - **Manufacturing**.Nebraska's rapidly growing industrial rate had a negative and statistically significant impact on the state's competitive manufacturing job gains.
            1. From 2008 to 2013, the competitive disadvantage of higher industrial rates, which rose from 5.16 to 7.44 cents per kWh, cost Nebraska an estimated 3,729 manufacturing jobs.
            2. From 2008 to 2013, a 10 percent increase in Nebraska's industrial electricity rates resulted in a loss of 2.3 percent in manufacturing jobs over and above changes at the regional and national levels (Tables A3.1 and A3.2).
            3. The Nebraska food processing industry is the fourth largest electricity user among manufacturers. Furthermore, Nebraska has a significant share of the nation's employment in this industry. Thus, Nebraska's rising and high industrial electricity rates present a significant financial hurdle for one of the state's most important industries (Table 3.6).

- **Agriculture**. Over the last five years, it is estimated that rising industrial electricity rates added significantly to farming expenses.
    1. The EIA (U.S. Energy Information Association) classifies Nebraska's electricity rates for agriculture industrial, and since Nebraska has a large number of farms that utilize irrigation, the state ranks third highest in terms of industrial users.[6] Low industrial rates are vital to the profitability and sustainability of farmers and agricultural producers. Recent trends in the industrial rate, however, have been unfavorable to Nebraska's farmers.
    2. The expenditures in electricity for Nebraska's agricultural sector have increased by 107.9 percent from 2004 to 2013, with a record high of $310.2 million in 2012.[7] (Figure 4.1)
    3. Industrial electricity rates and total electricity expenditures in Nebraska's agricultural sector have gone hand in hand, increasing significantly together. From 2001 to 2013, a 10 percentincrease in industrial rates produced a 3.6 percent increase in farm expenses throughout WNC states.
    4. Over the last five years, a total of $413.3 million of added farming expense for Nebraska can be attributed to increasing industrial electricity rates. (Table A5.1, Figure 4.3)
    5. The increasing trend in industrial rates is a threat to Nebraska's farmers and agriculture producers, particularly because many farmers rely on irrigation systems that are intensive users of electricity.[8]

V. Urban versus Rural Electricity Pricing in Nebraska

- Nebraska's public utilities, with a higher proportion of industrial customers, generally charge industrial rates significantly higher than utilities that serve primarily residential customers. (Table 4.3)
- During peak times, mainly July and August, demand for electricity, particularly from irrigation systems, sometimes exceeds capacity and forces local utilities to buy excess power from sources in other states, which if purchased at elevated prices contributes to higher overall rates.
- As expected, the costs of electricity lack uniformity across the state. Rural areas, particularly in the south and west portions of the state, have higher average industrial rates than utilities that serve more urban areas.
- Currently, public utilities hold the right of first refusal for power-related development projects, especially transmission projects. This gives incumbent developers the right of first refusal when bidding on state transmission line projects. Some politicians have suggested that this right results in a less competitive bidding process.[9] This argument centers on the idea that the right of first refusal for incumbent developers discourages companies from participating in a competitive bidding process. Rather, to increase competition in the bidding process, non-incumbent private companies should be welcomed and incentivized to bid on projects in Nebraska's electricity industry.

Key Findings

VI. The President's CO2 Reduction Program and Its Impact on Nebraska

- The Obama Administration's planned reduction in coal electricity generation will have a larger negative impact on Nebraska than on other WNC and U.S. states.
  - Nebraska's usage of coal as a fuel source for electricity generation in 2013 was more than twice that of the median for all U.S. states.
  - Coal is a relatively cheaper source of fuel for Nebraska due to the state's proximity to a large coal supply from Wyoming's Powder River Basin.
  - Except for solar, conventional coal is expected to experience the highest level of uncertainty regarding the range of expected prices from 2015 to 2020.
  - Due to Nebraska's heavy reliance on coal for electricity generation and the President's coal reduction program, input price volatility will be high, likely leading to higher volatility in electricity prices.
  - Nebraska prices, by boosting wind production 10 percent and by reducing coal production by 10 percent, would increase its overall electricity prices per kWh by 7.3 percent by 2018. (Figure 2.3)
  - In 2013, federal subsidies per kWh were 3.50 cents per kWh for wind, but a much lower 0.04 cents per kWh for coal. Without the subsidies, coal electricity production costs are significantly below that of wind.
  - Without federal electricity subsidies, Iowa's electricity rates would exceed those of Nebraska.
  - As a result of Nebraska's high coal usage and the President's coal reduction program, Nebraska's electricity price growth will likely exceed that of states that use less coal for electricity generation.

VII. Benefits and Costs of Privatization of Nebraska's Electricity Generators

- As a result of the limited market, Nebraska's two producers of electricity, OPPD and NPPD, are too small to take advantage of economies of scale that exist in power generation. Economies of scale are the cost advantages that a producer gains when more power can be generated on a larger scale and with lower input costs. These savings are typically achieved by satisfying the demands of an entire market with fixed costs spread out over more units of output.
- Between 2009 and 2014, Nebraska's electric generators' ratios of operating expenses to operating revenues were significantly above that of Mid-American Energy and the industry median.
  - The median industry operating expenses to operating revenues ratio was 82.9 percent, which was well below OPPD's 89.0 percent and NPPD's 88.1 percent.
  - Were both OPPD and NPPD able to achieve the industry average, savings would be significant. OPPD and NPPD could save an estimated $79.7 million and $85.7 million respectively for 2014. (Table 5.4)
- If privatized, Nebraska utilities would begin paying the relevant property tax rate rather than the current payments in lieu of taxes. The gain for local property taxing units would have been $61 million for 2014.
- Privatization would result in the loss of financial benefit of issuing tax exempt bonds. This loss is estimated to be $39.7 million for 2014.

Section 1: Introduction and Brief Overview of Public Power in Nebraska

Nebraska is the only state to distribute 100 percent of its electricity from public utilities. This is in contrast to most states, which usually rely on regulated investor-owned utilities for the generation, transmission, and distribution of power. In theory, public power should provide customers with lower prices compared to for-profit utilities since electricity prices do not include required profit margins. Historically that has been the case.

However, recent data show that Nebraska's electricity rates grew at a much faster pace than the rest of the nation and the WNC region. As a result, Nebraska no longer delivers electricity to consumers, both industrial and residential, at a rate below its chief competitors.

The categories of Nebraska power suppliers are:[10]

1. Municipalities
2. Agencies formed under the Nebraska Municipal-Cooperative Financing Act
3. Non-profit cooperatives
4. Rural public power districts
5. Large public power districts with generation facilities
6. Public power and irrigation districts

Table 1.1 presents a timeline of major Nebraska public power events.[11]

Table 1.1: Timeline of Major Nebraska Public Power Events

Date	Event
1887	Municipally owned electric systems begin operations in Crete, Nebraska.
1889	Nebraska Legislature authorizes cities to establish electric systems.
1902-1926	The number of municipal electric plants increased from 11 to 282.
1933	Nebraska legislature passed the Enabling Act that allowed and authorized the formation of public power and irrigation districts as public corporations and political subdivisions of the state.
1935	U.S. Rural Electrification Administration (REA) and Nebraska Rural Electric Association were established.
1946	The Nebraska Power Company was ordered to dissolve under the Public Utility Company Holding Act, with the formation of Omaha Public Power District.
1958	U.S. REA-financed rural electric systems are serving 95,050 farms, approximately 95 percent of total farms in the U.S.
1961	Nebraska Legislature established two committees: The Nebraska Public Power Committee composed of representatives of public power districts, and the Legislative Council Committee on Public Power, composed of state senators.
1963	Nebraska Legislature created the Nebraska Power Review Board to address problems of duplication and service area disputes.
1963	L.B. 220 granted the Board the authority to regulate construction of generation and transmission facilities in Nebraska. This authority allowed the Board to restrain suppliers from building generation capability when it was not truly needed, thus avoiding a surplus of electrical power, and unnecessarily raising the electric rates for the power supplier's customers.

Source: Nebraska Power Review Board Orientation Manual

APPENDIX NO. 34

The February Arctic Event

MISO,

February 14-28, 2021

(54 pages)

Copy available in office of Natural Resources Committee

THE FEBRUARY ARCTIC EVENT

FEBRUARY 14-18, 2021

EVENT DETAILS, LESSONS LEARNED AND
IMPLICATONS FOR MISO's RELIABILITY IMPERATIVE

MISO

misoenergy.org

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APPENDIX NO. 35

The History of Public Power in Nebraska

Legislative Research Office (LRO)

January 2018

PUBLIC POWER IN NEBRASKA

LEGISLATIVE RESEARCH OFFICE

January 2018

Public Power in Nebraska

A Legislative Research Office Backgrounder

Prepared by
Keisha Patent
Legal Counsel

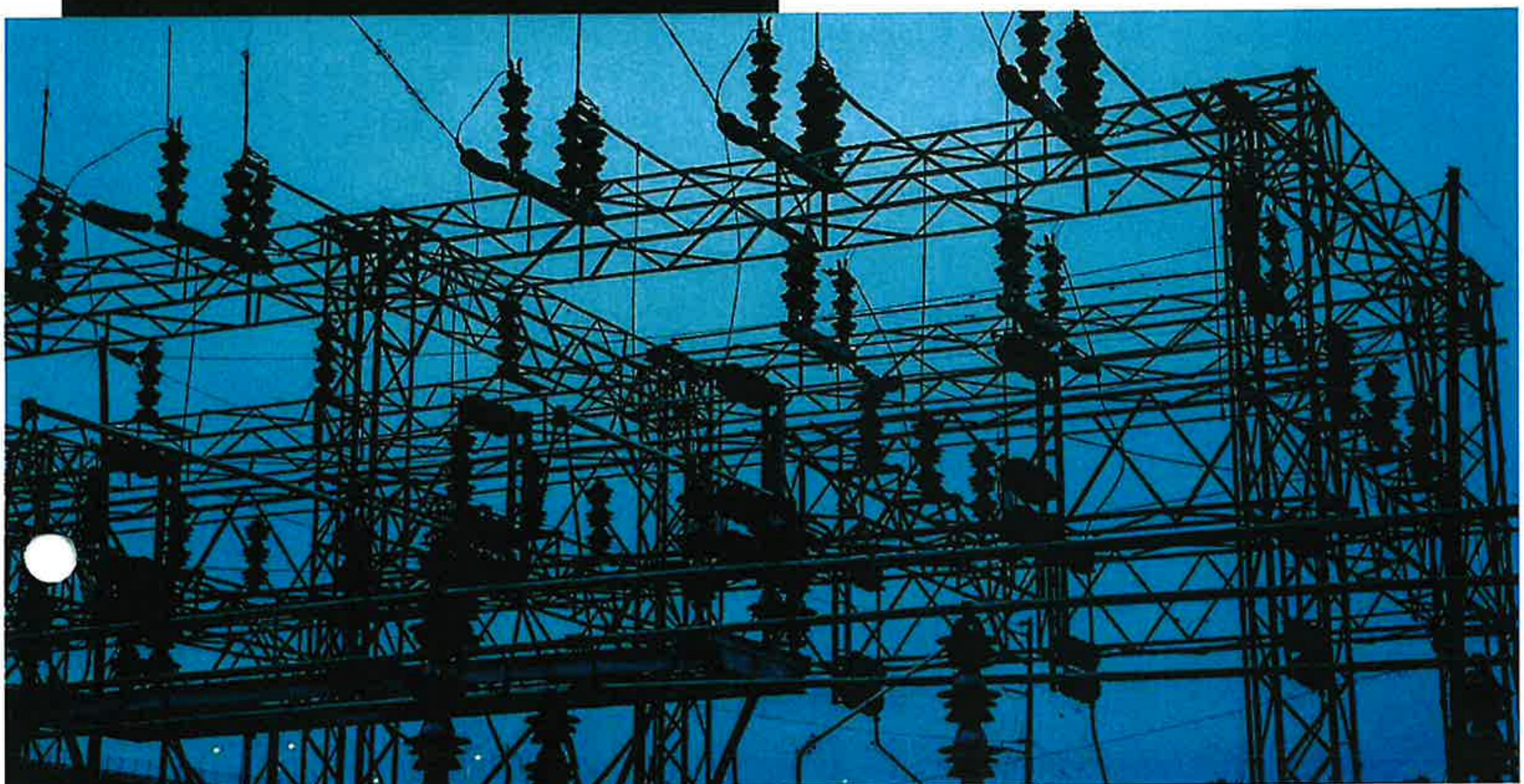
Designed by
Logan Seacrest
Research Analyst

January 2018

LEGISLATIVE
RESEARCH OFFICE

Research
Report
2018-1

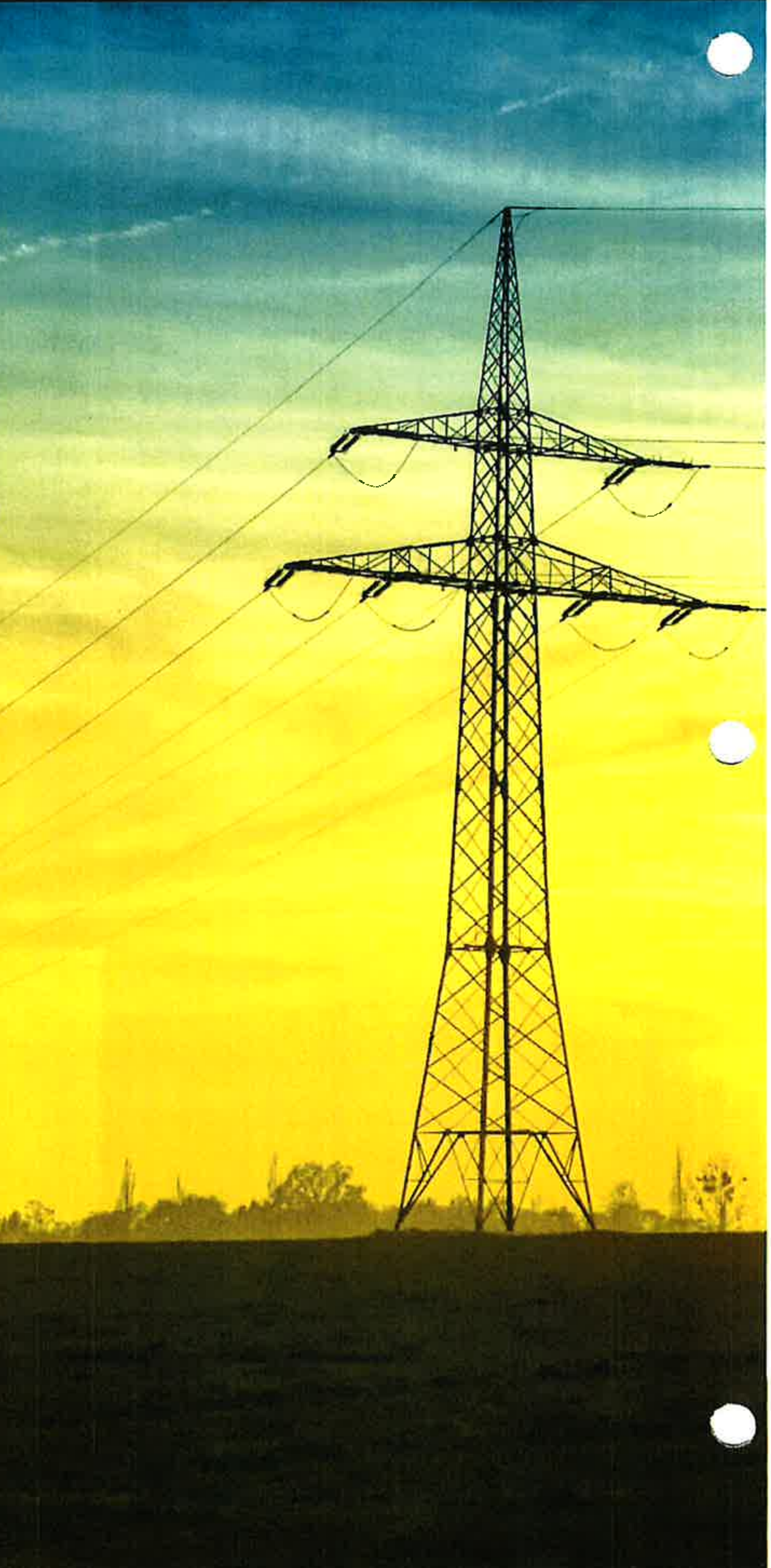
INTRODUCTION



Nebraska is often described as a public power state. But what does that mean? How did the state get the public power system that it has today, and where does Nebraska's system fit into the national picture?

This LRO Backgrounder— Public Power in Nebraska—is designed to provide a solid foundation and pertinent information regarding the structure and development of the public power system in Nebraska, what makes public power different, and the current regulatory and market landscape for electricity in the United States.

How is Nebraska's Electricity Industry Structured?



Electricity in Nebraska is supplied to consumers by customer-owned not-for-profit entities, including public power districts, cooperatives, and municipalities. We are the only state where this is true. In every other state, for-profit companies are involved in supplying electricity to consumers.

With the exception of some renewable energy generation facilities owned by private developers, generation and transmission of electricity throughout Nebraska is controlled by publicly owned entities or cooperatives.

Major Players in Nebraska's Electricity Industry Today

Nebraska Public Power District (NPPD)

NPPD derives its wholesale power supply from agreements with 46 towns and 25 rural public power districts and rural cooperatives in 86 of Nebraska's counties. NPPD also serves about 80 communities at the retail level. NPPD serves over 600,000 people and has over 5,200 miles of transmission lines.

Omaha Public Power District (OPPD)

OPPD serves a 13-county, 5,000 square mile area in southeast Nebraska. The service area includes over 800,000 people, including 47 towns at retail and five at wholesale.

Tri State Generation & Transmission (Tri-State G&T)

Tri-State G&T serves six public power districts in western Nebraska.

Nebraska Electric Generation and Transmission Cooperative, Inc. (NEG&T)

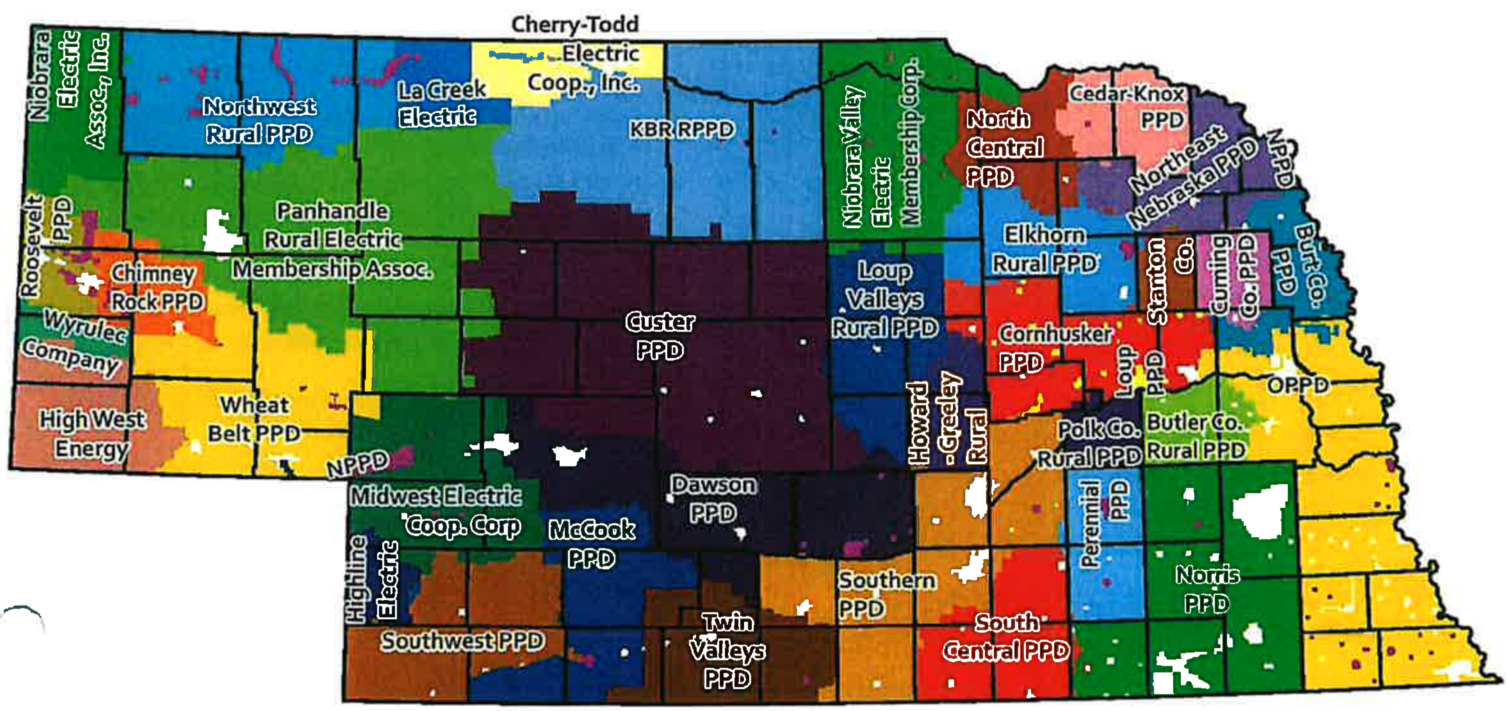
NEG&T's is a cooperative with membership from 20 public power districts and one electric membership corporation. It serves about 150,000 customers at retail in eastern Nebraska.

Nebraska Municipal Power Pool (NMPP)

NMPP has nearly 140 members in Nebraska, most of which are municipalities, and provides distribution, management, computer services, and energy research and development funds to its members. In addition, the Municipal Energy Agency of Nebraska is a wholesale supply organization of NMPP that provides supply and transmission to 42 municipalities in Nebraska and additional communities in Colorado, Iowa, and Wyoming.

The following map illustrates Nebraska's public power districts and rural cooperatives operating in 2017.

Nebraska Public Power Districts and Rural Electric Cooperatives 2017



The Cooper Nuclear Power Station near Brownville, NE is operated by Nebraska Public Power.

Nebraska's Power Review Board

The Nebraska Power Review Board regulates the electricity industry in the state.[1] The review board is composed of five board members, appointed by the Governor to four-year terms. Board members cannot serve more than two consecutive terms, and no more than three members can be from the Governor's political party. Members must include: an accountant, an attorney, an engineer, and two laypersons.

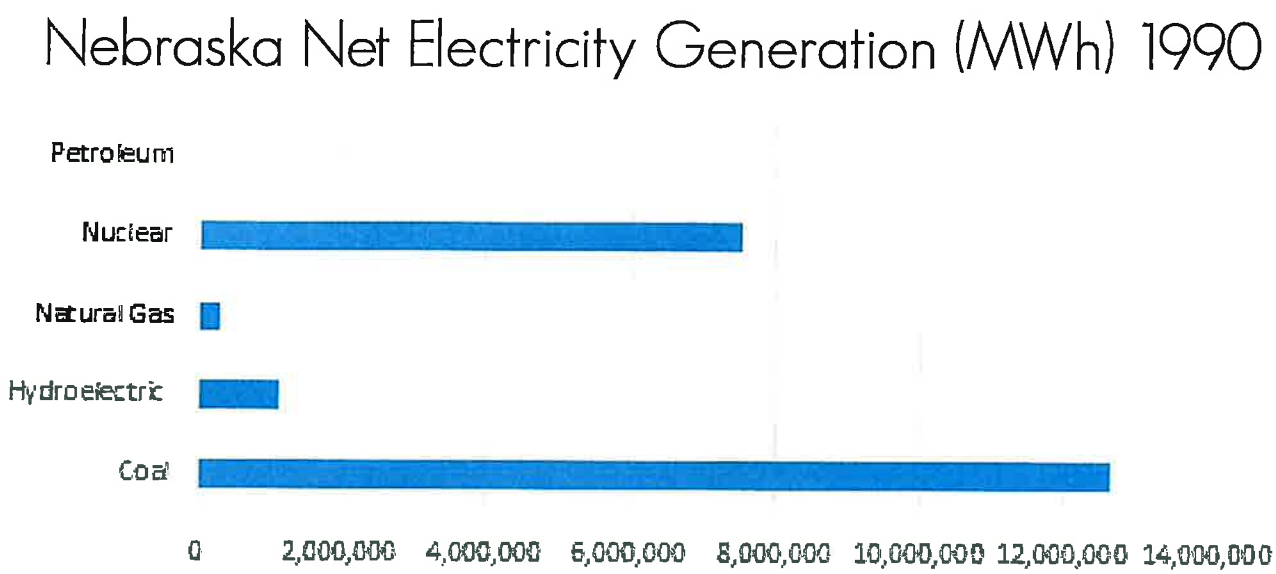
The review board:

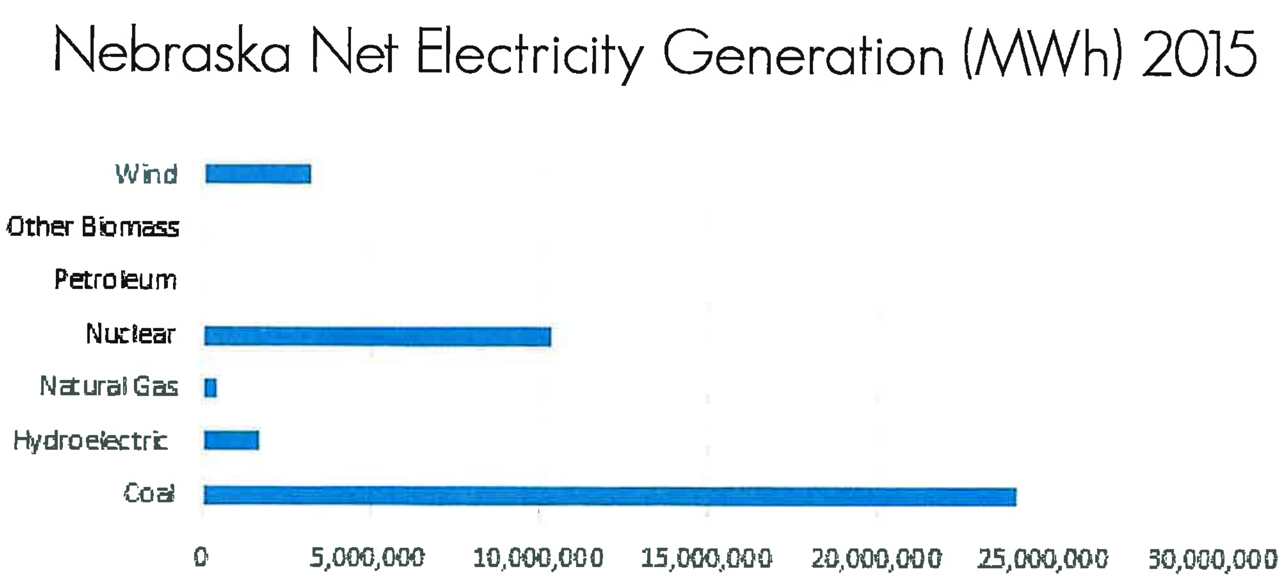
- Certifies utility service areas and agreements between public power districts, rural electric cooperatives, municipalities, or joint agencies to provide or sell wholesale and retail energy;
- Approves construction of new generation or transmission facilities with capacity of 700 volts or more, unless the new generation or transmission is within the utility's own certified service area or the facility is a privately developed renewable energy generation facility that meets certain enumerated requirements;
- Approves creation of new public power districts or amendments to districts' petitions for creation;
- Hears certain rate disputes between utilities and customers;
- Approves construction of microwave communication facilities; and
- Prepares an annual Power Supply Plan.

1. *Neb. Rev. Stat. secs. 70-1001 – 70-1028.*

Electricity Generation Statistics

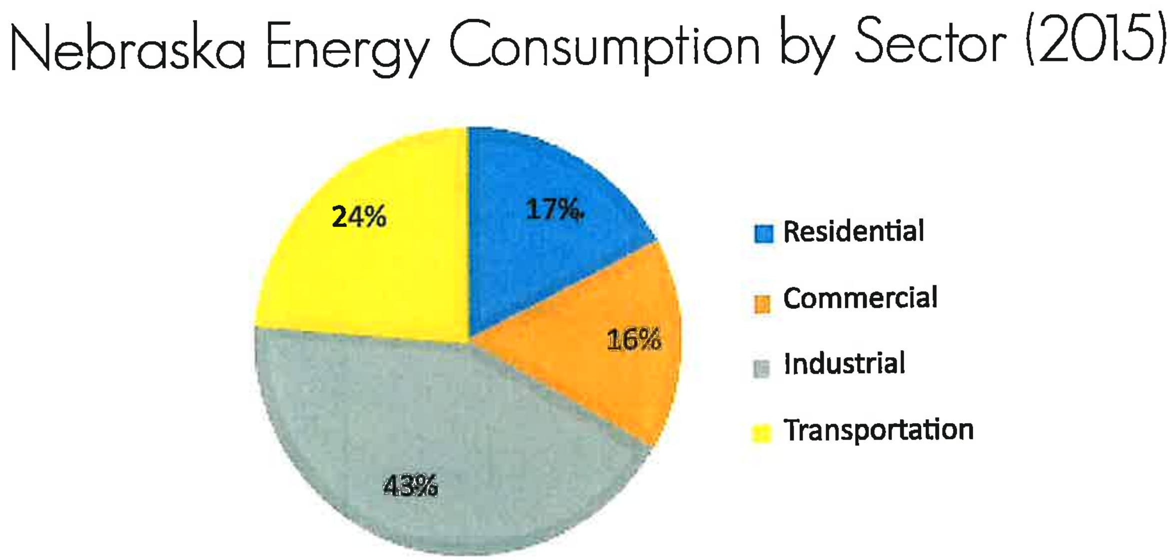
According to the United States Energy Information Administration (EIA), over the past 25 years, the source of electricity generation in Nebraska has changed. In 1990, the majority of electricity generation was produced from coal, with the remainder coming from nuclear or hydroelectric, and a much smaller percentage from natural gas. By 2015, the majority of electricity generation was still produced from coal, followed by nuclear, but in third place was wind generation. The following charts illustrate the net electricity generation for 1990 and 2015, respectively.



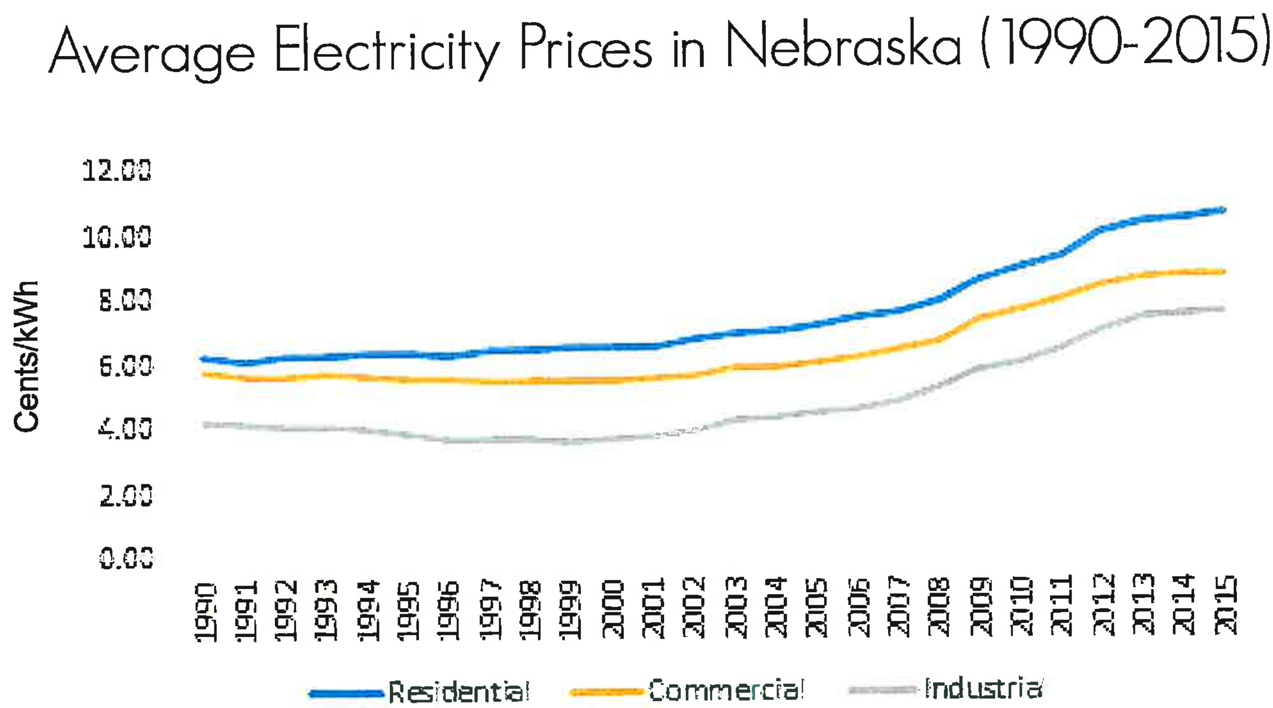


Nebraska's Electricity Consumption

In 2015, Nebraskans used 450 million Btus, ranking 7th nationally in per capita energy consumption, and expenditures were $4,326 per capita, which ranked 8th nationally. Nebraska had 825,940 residential customers, 149,820 commercial customers, and 60,556 industrial customers for the same time period. Total consumption of electricity by sector in Nebraska for 2015 is shown in the following chart.



As depicted, prices for electricity in Nebraska have risen relatively slowly over the past 25 years for residential, commercial, and industrial users.



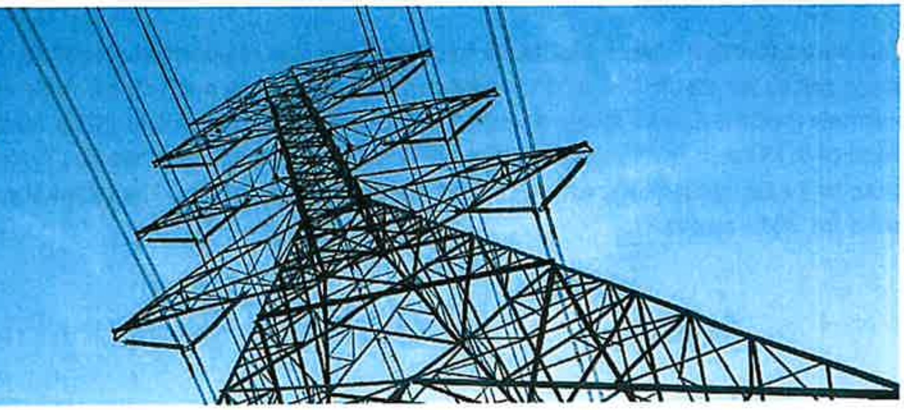
Compared to other states, Nebraska has relatively low residential electricity prices. EIA releases data on the monthly average prices for electricity sold to residential customers in each state. Nebraska has lower prices in winter months than summer months due to lower demand. For example, in December 2016, Nebraska had an average monthly residential price of 9.73 cents/kWh, which ranked 8th lowest nationally. In June 2017, Nebraska had an average monthly residential price of 12.06 cents/kWh, which ranked 19th lowest nationally. The following table shows each state's average annual price for 2016 and rank.

Average Annual Residential Electricity Price, cents/kWh (2016)

State	Price	Rank	State	Price	Rank	State	Price	Rank
Louisiana	9.11	1	West Virginia	11.22	18	Kansas	12.95	35
Washington	9.38	2	Florida	11.24	19	Delaware	13.47	36
Arkansas	9.90	3	Indiana	11.39	20	Pennsylvania	14.03	37
Idaho	10.00	4	Georgia	11.41	21	Maryland	14.23	38
Oklahoma	10.07	5	Virginia	11.42	22	Wisconsin	14.38	39
North Dakota	10.24	6	Nevada	11.42	22	Michigan	15.30	40
Kentucky	10.29	7	South Dakota	11.43	24	New Jersey	15.75	41
Tennessee	10.33	8	Colorado	12.02	25	Maine	15.80	42
Mississippi	10.54	9	Alabama	12.04	26	Vermont	17.33	43
Oregon	10.63	10	New Mexico	12.08	27	California	17.40	44
Nebraska	10.87	11	Arizona	12.21	28	New York	17.59	45
Missouri	10.89	12	Illinois	12.23	29	New Hampshire	18.43	46
Texas	11.02	13	Iowa	12.25	30	Rhode Island	18.63	47
Montana	11.04	14	Ohio	12.28	31	Massachusetts	19.11	48
Utah	11.08	15	South Carolina	12.44	32	Connecticut	20.00	49
North Carolina	11.14	16	Minnesota	12.73	33	Alaska	20.61	50
Wyoming	11.18	17	D.C.	12.87	34	Hawaii	27.46	51

Nebraska is among the top 10 states in per capita energy consumption because of its energy-intensive industrial sector, led by food processing, chemical manufacturing, and agriculture.

State Electricity Profiles 2015



EIA publishes state electricity profiles that include the net generation in megawatt hours (MWh), and total retail sales in megawatt hours (MWh) for each state. For 2015, the most current reported year, Nebraska produced more than 10 million MWh of electricity than it sold at retail.

Name	Net generation (MWh)	Total retail sales (MWh)
Alabama	152,477,427	88,845,543
Alaska	6,284,937	6,159,204
Arizona	113,142,048	77,349,416
Arkansas	55,559,428	46,465,154
California	196,703,858	261,170,437
Colorado	52,393,077	54,116,046
Connecticut	37,470,622	29,476,155
Delaware	7,810,006	11,498,205
DC	53,750	11,291,233
Florida	237,412,633	235,599,398
Georgia	128,817,898	135,878,215
Hawaii	10,119,500	9,511,352
Idaho	15,667,095	23,058,814
Illinois	193,952,040	138,619,970
Indiana	104,019,275	104,514,518
Iowa	56,658,918	47,147,293
Kansas	45,527,124	39,849,127
Kentucky	83,543,671	76,038,630
Louisiana	107,812,354	91,676,489
Maine	11,741,265	11,888,168
Maryland	36,365,544	61,781,719
Massachusetts	32,085,969	54,621,088
Michigan	113,008,050	102,479,921
Minnesota	56,979,768	66,579,234
Mississippi	64,757,864	48,691,529
Missouri	83,640,067	81,504,081

Name	Net generation (MWh)	Total retail sales (MWh)
Montana	29,302,401	14,206,911
Nebraska	39,883,391	29,495,073
Nevada	39,046,784	36,019,690
New Hampshire	20,015,893	10,999,149
New Jersey	74,608,860	75,489,623
New Mexico	32,701,398	23,093,553
New York	138,627,721	148,913,655
North Carolina	128,388,445	133,847,523
North Dakota	37,156,612	18,128,948
Ohio	121,893,401	149,213,224
Oklahoma	76,135,596	61,336,385
Oregon	57,866,535	47,263,974
Pennsylvania	214,572,291	146,344,028
Rhode Island	6,939,019	7,664,718
South Carolina	96,532,213	81,328,246
South Dakota	9,633,033	12,101,979
Tennessee	75,214,636	99,632,108
Texas	449,826,336	392,337,354
Utah	41,949,120	30,192,350
Vermont	1,982,047	5,521,109
Virginia	84,411,592	112,009,045
Washington	109,287,458	90,116,086
West Virginia	72,295,269	32,303,026
Wisconsin	66,360,183	68,698,932
Wyoming	48,966,519	16,924,762
U.S. Total	**4,077,600,939**	**3,758,992,390**

What Makes Public Power Different?

Electricity in the United States is generated, transmitted, and distributed at retail by many different types of entities, and these entities employ different business models, vary in size and scope, and are subject to different regulatory oversight.

Types of Utility Ownership

The types of entities that generate, transmit, and distribute electricity include:[2]

- Public power utilities, which are owned by governmental units, including municipalities, states, public utility districts, irrigation districts, or joint agencies. Public power utilities vary in size and scope: Some are small distribution utilities and some are large, vertically integrated utilities. As publicly owned entities, public power utilities are exempt from certain taxes.

- Rural electric cooperatives, which are nonprofit member-owned utilities where members hold voting and ownership rights and management is elected by the membership. Cooperatives receive federal funding through the Department of Agriculture's Rural Utility Service and cooperative banks and are exempt from income tax.

- Federally owned utilities, which operate in many areas of the country. There are five federally owned utilities: (1) Tennessee Valley Authority (TVA); (2) Bonneville Power Administration (BPA); (3) Southeastern Power Administration (SEPA); (4) Southwestern Power Administration (SWPA); and (5) Western Area Power Administration (WAPA).

  TVA is an independent government corporation that provides electricity for customers and distributors and provides flood control and management of the Tennessee River system. TVA is generally funded by electricity revenue, rather than taxpayer funding.

  The other four federally owned utilities are entities within the Department of Energy. BPA, SEPA, SWPA, and WAPA are Power Marketing Administrations (PMAs) that maintain transmission infrastructure and market hydroelectric generation at dams operated by the Bureau of Reclamation or the Army Corps of Engineers. The PMAs also own and operate thousands of miles of transmission lines linked with the systems of other utilities.

- Investor-owned utilities, which are privately owned, for-profit businesses whose retail service is regulated by state regulatory commissions, and as such, receive a regulated rate of return based on investments made to serve the ratepayers. Investor-owned utilities can be vertically integrated or own transmission or distribution components.

- Independent power producers, which sell electricity through markets and contracts with utilities and other customers. Independent power producers base electricity prices on the market, rather than costs, and often have highly fluctuating returns.

- Competitive retail energy suppliers, which sell electricity to customers in states with retail markets, and therefore, do not earn a regulated rate of return. These companies supply power to customers and can offer competitive pricing and customer service. However, retail energy suppliers do not transmit or deliver the electricity but contract with utilities or other entities for those services.

- Energy service companies, which develop and implement projects aimed at improving energy efficiency, reducing costs of operation, or reducing capacity constraints. These companies provide these services using performance-based contracts that are tied to the cost savings associated with the projects.

- Demand-response aggregators, which contract with customers to reduce electricity consumption in exchange for financial incentives during periods of high demand or prices, system constraints, or emergencies. Existing utilities and third-party providers can serve as demand-response aggregators, and aggregators can participate in the energy and capacity markets.

> A public power system differs from other types of electricity systems because of the ownership structure of the utilities that provide the electricity: Electricity is provided to customers by governmental and other types of nonprofit entities, such as cooperatives, in a public power system.

2. United States Department of Energy, Quadrennial Energy Review, Second Installment, January 6, 2017.

Utility Ownership in Nebraska

The following table from the United States Department of Energy, prescribes the most common types of utility ownership nationally:

Utility Type	Number of Utilities	Number of Customers	Miles of Power Lines	
			Transmission	Distribution
Investor-Owned Utilities	169	107,566,949	3,467,216	459,480
Municipal Utilities	1,834	15,151,058	320,953	27,585
Rural Electric Cooperatives	814	19,232,195	2,397,111	116,635
Federal and Publicly Owned Utilities	124	5,280,112	333,720	95,962
Total	**2,941**	**147,230,314**	**6,519,000**	**699,662**

Nebraska has rural electric cooperatives and publicly owned entities (public power districts and municipally owned entities) that provide electricity service to consumers. Nebraska is also within the 15 state region of the federally owned Western Area Power Administration.

Public power districts in Nebraska are political subdivisions and are subject to:

- The Elections Act in the election of board members;[3]
- The Open Meetings Act;[4]
- Annual audit requirements by the Auditor of Public Accounts;[5] and
- Requirements to have all books and records open to public inspection.[6]

Public power districts are exempt from income and property taxation, but do pay in lieu of tax payments to local political subdivisions as a substitute for property taxes.[7] In 2016, the total in lieu of tax paid by public power districts was $46,061,323.73.[8]

Renewable energy generation facilities pay a nameplate capacity tax instead of personal property tax.[9] The tax is $3,518 per megawatt of production capacity of the facility. Total nameplate capacity tax collected in 2016 was $2,649,229.[10]

Public power districts cannot levy a property tax or issue general obligation bonds paid by tax revenue for operating expenses, but can issue revenue bonds for capital expenses.[11]

Rural electric cooperatives are nonprofit organizations where management is elected by members with voting rights. Cooperatives are not political subdivisions, so are not exempt from property tax or subject to the same open meeting or audit requirements as public power districts. Cooperatives can be formed under statutory provisions dealing with power districts or as nonprofit corporations.[12]

Currently, there are no investor-owned utilities, competitive retail energy suppliers, energy service

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3. Neb. Rev. Stat. sec. 70-610.
4. Neb. Rev. Stat. secs. 84-1407 – 84-1414.
5. Neb. Rev. Stat. sec. 70-623.02.
6. Neb. Rev. Stat. sec. 70-622.
7. Neb. Rev. Stat. secs. 70-651.01 – 70-651.05.
8. Nebraska Department of Revenue, Annual Report, Table 21A, accessible at http://www.revenue.nebraska.gov/PAD/research/annual_reports/2016/annrpt2016_table_21.pdf.
9. Neb. Rev. Stat. sec. 77-6203.
10. Nebraska Department of Revenue, Nameplate Capacity Tax Summary, accessible at http://www.revenue.nebraska.gov/research/misc_tax_data.html.
11. Neb. Rev. Stat. secs. 70-629, 70-631.
12. Neb. Rev. Stat. sec. 70-701 et seq. and 70-801 et seq.

An Example from Iowa

In most other states, the majority of electricity is supplied to consumers by investor-owned utilities. For example, in Iowa, approximately three-fourths of customers are served by two of these utilities.

The Iowa Utilities Board 2016 Iowa Utility Electric Profile details supply of electricity in the state. According to the profile, two investor-owned utilities served 72.21 percent of customers in the state and had 75.08 percent of total retail sales. There were 136 municipally owned utilities, which provided service to 13.47 percent of customers and accounted for 11.07 percent of total retail sales. Forty-four utilities were rural cooperatives, which served 14.32 percent of customers and accounted for 13.85 percent of total retail sales.

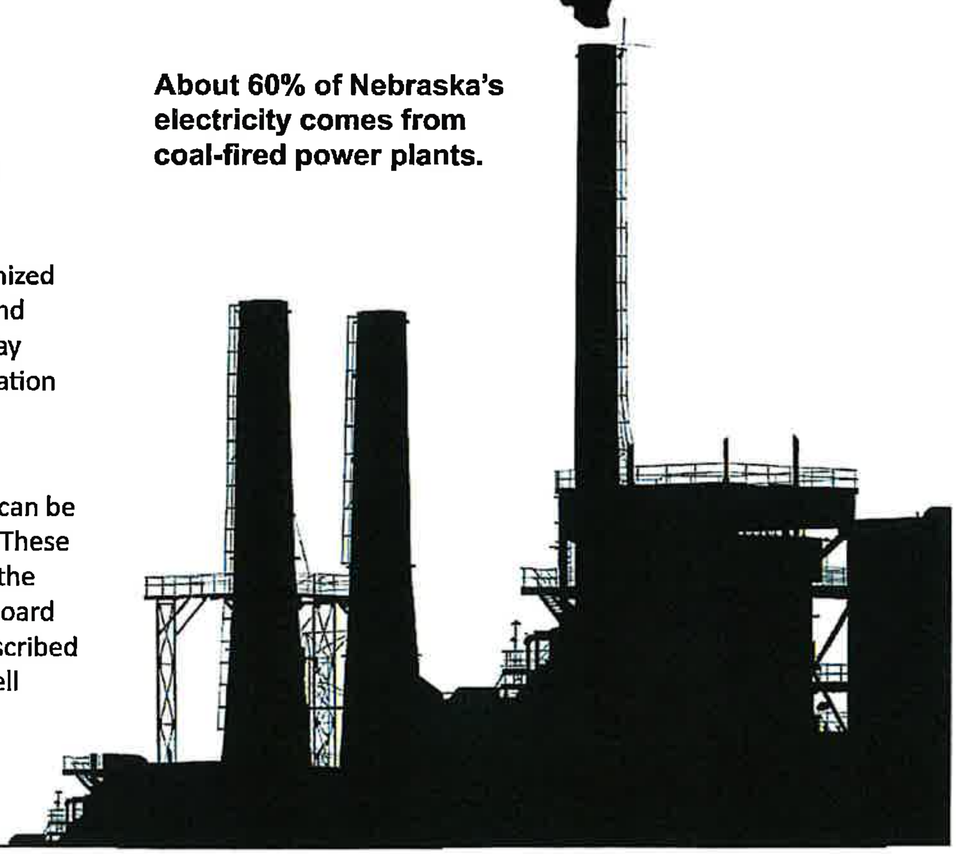
In addition, according to a 2016 Energy Information Administration report listing power plants by state, plants in Iowa are owned by investor-owned utilities, municipalities, rural cooperatives, and independent power producers. Iowa has four cooperatives operating only in generation and transmission of electricity.

companies, or demand-response aggregators operating in Nebraska.

Generally, Chapter 70 of the Nebraska Reissue Revised Statutes limit electricity generation, transmission, and retail activity in the state to public power districts, rural cooperatives organized as power districts or nonprofit corporations, and municipalities. However, private companies may engage in developing renewable energy generation facilities, subject to certain requirements.

Many of Nebraska's wind or solar generation facilities are owned by private companies and can be categorized as independent power producers. These generation facilities are exempt from many of the requirements of the Nebraska Power Review Board and have a simplified approval process, as prescribed in Laws 2016, LB 824, but are not allowed to sell electricity at retail in the state.[13]

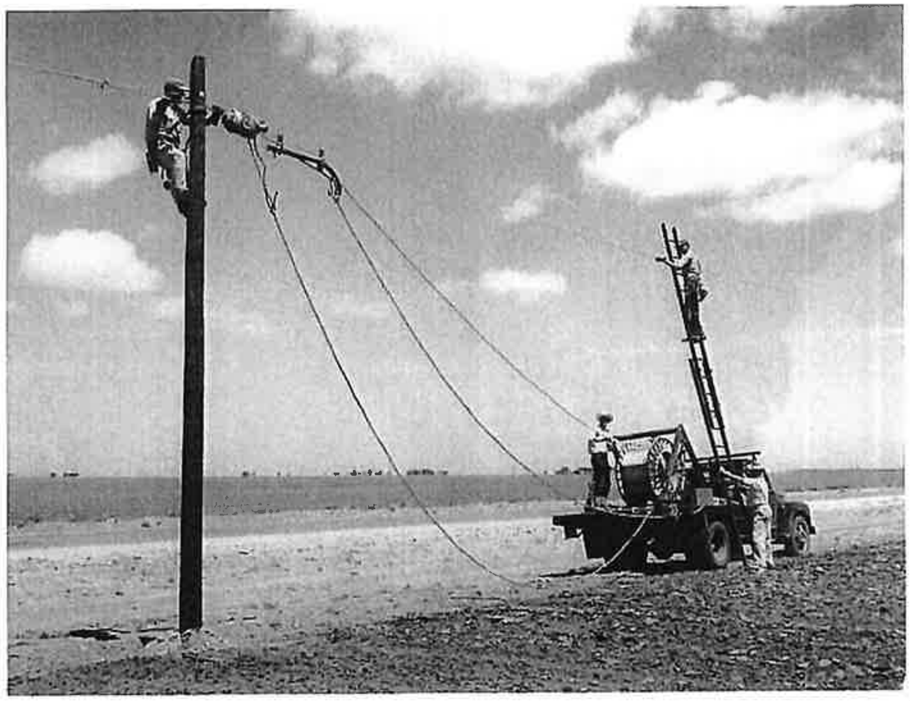
About 60% of Nebraska's electricity comes from coal-fired power plants.



13. Neb. Rev. Stat. secs. 70-1012 – 70-1014.02.

How Did Nebraska Become a Public Power State?

The Nebraska Legislature first authorized municipalities to contract for and regulate the operations of electric utilities in 1885. The first municipal electric utility was formed in Crete in 1887. By 1926, there were 282 municipal electric utilities in the state. In addition, 56 private companies provided electricity during this time, and rural cooperatives began to develop to provide service to agricultural customers.



The U.S. Rural Electrification Administration was created in 1935 to provide electric service to rural America.

During this same time period, five holding companies formed in Nebraska, merging private and municipal utilities. Because public utilities often lacked the capital to improve their facilities, they were more susceptible to the consolidation efforts of holding companies. In 1930 voters passed Initiative 324 authorizing revenue bond financing for municipal utilities, aiding them in obtaining capital financing.

In 1933, Nebraska lawmakers passed Senate File 310, also called the "Enabling Act." The Enabling Act essentially created public power districts by authorizing 15 percent of eligible voters to petition to form a public power and/or irrigation district in an area (a county, several counties, or a number of voting precincts). The board of directors for the district was prescribed by each petition.

Federal funding via the Public Works Administration and Rural Electrification Act contributed to the support for public power development in the state. In addition, the enactment of the federal Public Utility Holding Company Act of 1935 (PUHCA) forced the dissolution and restructuring of the holding companies after widespread abuse was found. Litigation continued over implementation of the PUHCA until the U.S. Supreme Court's decision supporting the breakup of the holding companies, causing a sell-off of their assets between 1940 and 1942.[14]

Between 1933 and 1943, 16 public power and/or irrigation districts and 35 rural electrification districts were formed in Nebraska. In 1939, the Legislature amended the Enabling Act, allowing a power district to act as a wholesaler for other power districts.[15] Consumers Public Power District was established as a result. A joint operating agreement for the three hydropower plants in the state was also created in 1940. The Nebraska Public Power System was created to carry out these agreements and to act as a wholesale marketing and transmission agency.

By 1942, most of Nebraska used public power. The exception was the city of Omaha. OPPD was formed in 1946 and acquired the assets of the privately owned Nebraska Power Company. The last privately owned power company was transferred to the North Central Public Power District in 1949, and Nebraska, at that time, became an all-public-power state.

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14. Electric Bond & Share Co. v. SEC, 303 U.S. 419 (1938).
15. Laws 1939, LB 170.

Mid-Century: Growth of Oversight and Organization

During the 1950's and 1960's, access to electricity expanded from 25 percent of rural homes to 95 percent. Tensions arose over contested service areas, construction of new energy generation, and access to power. Legislative efforts focused on reorganization and creating public oversight over the system. Due to the passage of a 1958 ballot initiative amending the Nebraska Constitution, the Legislature enacted a bill the following year requiring public power districts to make payments in lieu of property taxes.[16]

Laws 1963, LB 220, created the Power Review Board. The board's primary responsibilities were to resolve disputes over service territory, review and approve proposed generation and transmission facilities, and provide advisory opinions for resolution of rate disputes. The bill required the board to be composed of one engineer, one attorney, one accountant, and two laypersons, all appointed by the Governor. Today, membership remains the same.

Lawmakers were also concerned about overlapping generation and transmission entities. Laws 1965, LB 764, known as the "Grid Bill," forced consolidation of several power districts, but the bill was declared unconstitutional in *Whittler v. Bumartner*, 180 Neb. 446 (1966). A constitutional amendment to create public electrical corporations for wholesale generation and transmission failed on the ballot in 1968.[17]

Continuing pressure on public power districts led to the voluntary merger of operations, and as a result, NPPD was formed in 1969. Initially, NPPD served 87 of the 93 counties and more than 200 municipalities in addition to controlling most of the state's electricity transmission. Tri-State G&T continued to serve rural cooperatives and districts in the western region, OPPD served the southeast region, NEG&T served numerous rural electric systems, and independent municipalities provided their generation and contracts.

In the 1970s rising costs and environmental restrictions led many small municipal systems to look for alternatives, such as signing with NPPD as a wholesale supplier. Some municipal systems formed NMPP in 1975. NMPP allowed its 19-member municipal systems to own larger generating plants and acquire wholesale power supplies.

Studies and legislation during the 1970s related to efforts to reduce electricity costs, negotiate contracts, and change service requirements. In 1979, legislation authorized arbitration for rate disputes, and the Power Review Board was required to review additions to municipal generating capacity using a three-part test.[18] In 1981, the review board was required to produce and publish power supply planning information or work with the industry to do so.[19] As a result of the 1981 legislation, the Nebraska Power Association developed a statewide plan. The Nebraska Power Association, formed in 1980, is a voluntary organization representing entities involved in generating, transmitting, and supplying electricity in Nebraska.

In 1982, the Legislature adopted the Joint Public Power Authority Act, which authorized entities to create a joint authority to issue revenue bonds for capital financing for large projects.[20]

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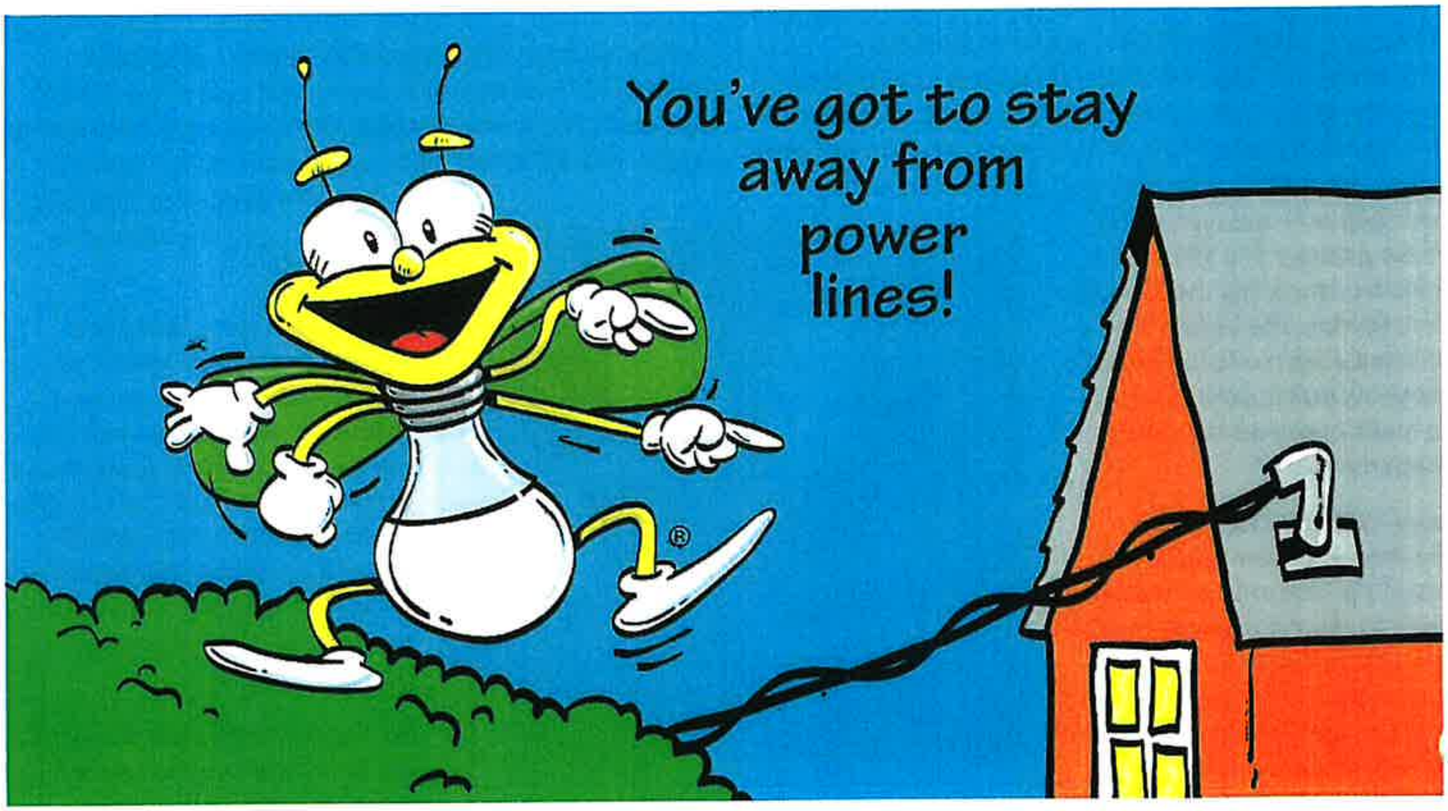
16. The ballot initiative was proposed by a voter petition. In lieu of tax payments were implemented by Laws 1959, LB 272.
17. Laws 1967, LB 107, placed the constitutional amendment on the 1968 ballot.
18. Laws 1979, LB 207; Laws 1979, LB 223.
19. Laws 1981, LB 302.
20. Laws 1982, LB 852.

The End of the Century: Deregulation and Competition



Louie the Lightning Bug was NPPD's electrical safety mascot during the 1990s and 2000s.

Following the federal implementation of the Public Utilities Regulatory Policies Act (PURPA) in 1978, throughout the 1980s and 1990s, the Nebraska Legislature and the Power Review Board studied deregulation of the electric industry.

In 1996, the Legislature adopted LR 455, which authorized a two-phase study of the structure of the electric utility industry and potential industry deregulation. LR 455 created a task force of industry representatives, hired an outside firm to prepare a research report and facilitate the process, and created an advisory group of 41 consumer advocates, environmentalists, business representatives, industry leaders, and legislators.

As a result of LR 455, the Legislature passed LB 901 in 2000. The bill required the Power Review Board to hold public hearings on retail electrical competition and to report annually whether the state would benefit from competition in the industry. In 2001, LB 243 was passed. LB 243 accommodated mergers and consolidations of public power districts by allowing a board of a merged or consolidated district to negotiate rates for consumers in predecessor districts that differ from rates in the remaining service area. LB 243 also allowed districts to negotiate different rates for business and industry customers who have entered into an economic development project, subject to certain limitations.

Enacted legislation in 2004 and 2006[21] focused on improving efficiency: (1) authorizing public entities to enter into electrical service purchase agreements and ownership agreements for electric facilities so public entities could share the costs of building large power plants; and (2) adopting the Public Entities Mandated Project Charges Act. This act ensured financing for the costs of mandated improvement projects, including generation, transmission, or distribution facilities, for public power entities, by allowing entities to charge customers a surcharge for the costs of such projects and repay bonds with the dedicated revenue collected from the customer payments.

21. Laws 2004, LB 969; Laws 2006, LB 548.

The Past Decade: Renewables

Legislation has largely focused on renewable energy in the last ten years.

Laws 2007, LB 629 created the Community-Based Energy Development (C-BED) program, a framework for local initiatives in wind energy development. Program projects must meet certain local ownership requirements, must be approved by the Power Review Board, and can negotiate power purchase agreements. In 2014, via passage of LB 402, the C-BED program was expanded to include other types of renewable energy. LB 402 also changed the local ownership restrictions to make C-BED more accessible.

A statewide net metering policy was adopted in 2009 by LB 436, which allows for interconnection between customer-generators and local distribution systems. Net metering policies apply to renewable energy facilities, including methane, wind, solar power, biomass, hydropower, or geothermal power at the premises of customer-generators.

Laws 2010, LB 1048 encouraged private renewable energy generation by creating a process for the Power Review Board to authorize certified renewable export facilities (CREFs) that meet certain requirements. Laws 2014, LB 1115 authorized the Power Review Board to commission a study of transmission infrastructure and policy, relating specifically to renewable energy. The resulting study, known as the Brattle report, identified several concerns relating to development of renewable energy generation, including the number of requirements in the CREF approval process and transmission constraints. As a result, LB 824 passed in 2016. LB 824 exempted privately owned renewable energy generation facilities from various requirements, simplifying the CREF approval process, but prohibiting private electric suppliers from selling or delivering electricity at retail in Nebraska.

The National Renewable Energy Laboratory estimates that more than 90% of Nebraska has suitable conditions for commercial-scale wind-powered electricity generation.

How Does Nebraska Fit into the National Landscape?

Nebraska's public power industry fits into a larger national picture, participating in organizations that (1) enforce federal regulations and (2) coordinate interstate transmission and markets for electric generation. A discussion of these organizations, and how they impact Nebraska, follows. A more detailed discussion of significant federal legislation and rulemaking is found in Appendix A.

First created in 1920 as the Federal Power Commission, the Federal Energy Regulatory Commission (FERC) is the main national regulatory authority. FERC is an independent agency within the Department of Energy and regulates the transmission and wholesale sale of electricity, provides market oversight, and ensures reliability of the electric grid in the United States.

The National Energy Policy Act, enacted by Congress in 2005, created a certification process for an electric reliability organization (ERO) to approve and enforce reliability standards, subject to FERC oversight, for all users, owners, and operators of the bulk-power system in the country. The North American Electric Reliability Corporation (NERC) is the certified ERO responsible for enforcing standards, assessing reliability, monitoring the electric system, and certifying personnel. NERC's authority spans most of North America and is subject to government oversight in the United States and Canada.

Eight regional entities work with NERC to maintain the electrical system by assisting with monitoring and enforcement of reliability standards across the country.

These entities include the:

- Western Electricity Coordinating Council (WECC);
- Midwest Reliability Organization (MRO);
- Northeast Power Coordinating Council (NPCC);
- Southwest Power Pool (SPP);
- Texas Reliability Entity (TRE);
- ReliabilityFirst (RFC);
- SERC Reliability Corporation (SERC); and
- Florida Reliability Coordinating Council (FRCC).

Important Acronyms

FERC: Federal Energy Regulatory Commission
NERC: North American Electric Reliability Corporation
ERO: Electric Reliability Organization
RTO: Regional Transmission Organization
MRO: Midwest Reliability Organization
SPP: Southwest Power Pool

Approximately 1,400 U.S. entities are registered with NERC and meet applicable reliability standards. Nebraska's utilities—NPPD, OPPD, and Lincoln Electric System—are members of MRO in its capacity as an ERO. Tri-State G&T, which operates in the western part of the state, is a member of the WECC ERO. Map 1 depicts the eight regional entities in their capacity as EROs.

The map also shows the three separate electrical grids in the U.S.: one in the eastern part of the country, one in the west, and one that covers most of Texas. The portion of western Nebraska served by Tri-State G&T is in the Western Interconnection. Notably, the grid in Texas is not interconnected to the rest of the county, and therefore, is not regulated by FERC.

In addition to regional EROs assisting with enforcement of reliability standards, there are also organizations that serve as regional transmission organizations (RTOs). RTOs are often the same organizations as EROs, but may cover different areas for this separate purpose. RTOs operate and manage the transmission system and offer a market structure for entities selling electric generation.

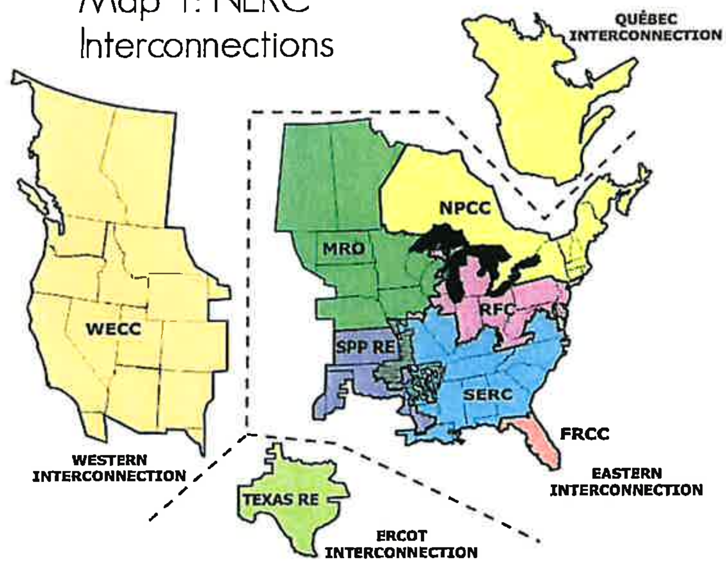
Nebraska's utilities are members of the Midwest Reliability Organization for enforcement of reliability standards but members of the Southwest Power Pool (SPP) in its capacity as a regional transmission organization. SPP became an RTO in 2004 and manages transmission and wholesale markets in 14 states, serving about 17.5 million people. Members of SPP include investor-owned utilities, municipal systems, generation and transmission cooperatives, state agencies (such as NPPD), independent power producers, power marketers, and independent transmission companies. SPP oversees 790 generating plants, 4,835 substations, and 65,755 miles of transmission lines.

Map 2 shows the area served by the SPP in its capacity as an RTO as of July 2017. This area is larger than the area currently served by the SPP in its capacity as an ERO (see Map 1.)

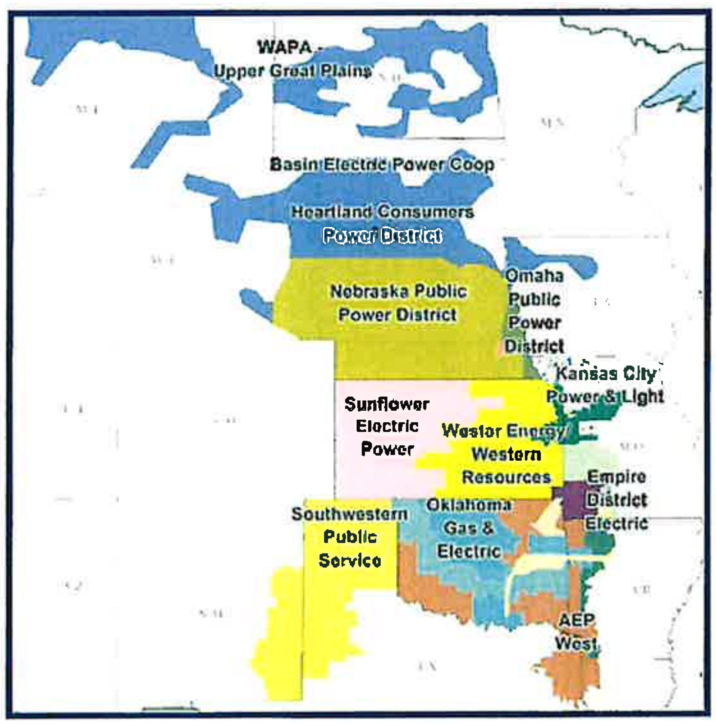
SPP assists members with planning new transmission projects, interconnecting transmission projects to the current grid, and studying potential upgrades to meet transmission service needs. SPP also manages the wholesale marketplace for energy in its member states through the Integrated Marketplace by:

- Providing infrastructure and systems to facilitate the market;
- Setting prices and handling monetary exchanges to financially settle the market; and

Map 1: NERC Interconnections



Map 2: Southwest Power Pool



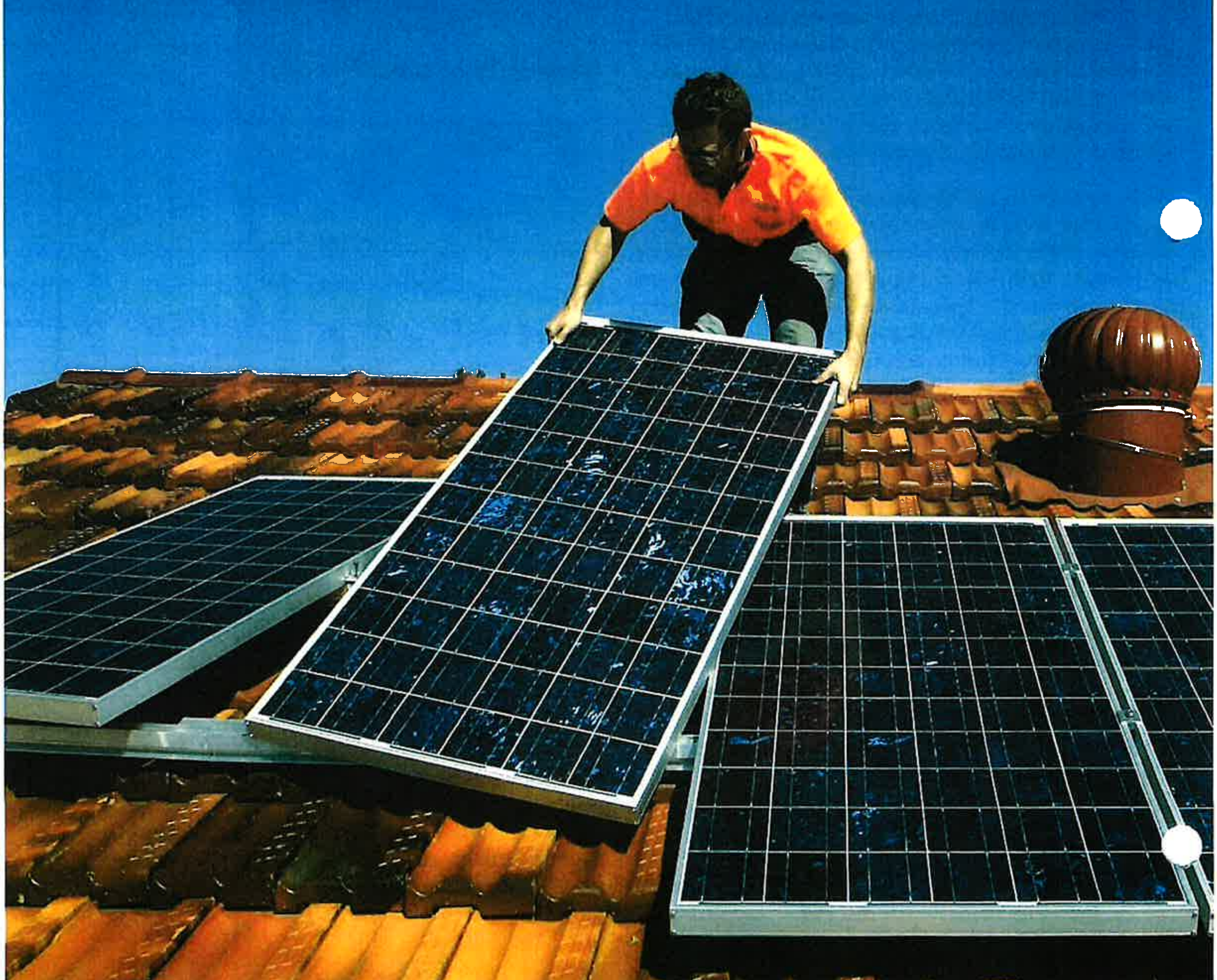
- Monitoring the market to provide oversight.

SPP has a Regional State Committee, comprised of representatives from its member states' retail regulatory commissions. The committee allocates transmission rights, allocates costs for transmission upgrades, and addresses regional resource adequacy. One member of the Nebraska Power Review Board is designated to represent the board on the committee.

Looking to the Future

Policymakers continue to study Nebraska's public power system. In 2017, bills were introduced relating to development of wind, solar, and other forms of renewable energy; net metering; and the authority of public power districts to use eminent domain.

Additionally, legislation was introduced to allow private companies to supply electricity to customers in competition with public entities. This past summer, the Legislature's Natural Resources Committee conducted an interim study, LR 125, evaluating public power and potential for competition in retail markets in Nebraska. Ongoing discussion of these issues continues.



Appendix: Federal Law

Federal law has shaped the regulatory landscape for electric utilities and created the framework for utilities to function over the years. Following is a timeline of major federal legislation impacting the electricity industry. This federal structure serves as the backdrop for the industry today.

- 1920: The Federal Water Power Act created the Federal Power Commission (now the Federal Energy Regulatory Commission (FERC)) to oversee the development of hydropower in the United States by entities not owned by the federal government. Amended in 1935, the act expanded the jurisdiction of the commission to regulate interstate electricity transmission and wholesale electricity sales, including rates, terms, and conditions of service.

- 1935: The Public Utility Holding Company Act (PUHCA) authorized regulation of public utility holding companies' financial transactions by the Securities and Exchange Commission and prohibited certain business structures. The act significantly reduced the number and impact of holding companies in the electricity markets in the United States.

- 1978: The Public Utilities Regulatory Policies Act (PURPA), part of the National Energy Act, required utilities to buy power from qualifying facilities at "avoided-cost" prices that were: (1) just and reasonable to the electricity consumers and in the public interest, (2) nondiscriminatory with respect to qualifying facilities, and (3) less than or equal to the incremental cost to the electric utility of alternative electric energy. As a result, PURPA led to creation of a new generation-only sector of the electricity market. PURPA also required state regulatory commissions and utilities to implement policies, such as time-of-day rates, cost-of-service for different classes of customers, master metering, and load management techniques.

- 1992: The National Energy Policy Act (NEPA) required transmission providers to provide service to third parties; adopted energy efficiency measures, such as requiring states to adopt building codes and equipment standards; and offered incentives for renewable energy development.

- 1996: FERC Order 888 and Order 889 encouraged competition in wholesale electricity markets. Order 888 required utilities that own or operate transmission to separate transmission and power marketing functions, offer transmission service to others under the same conditions they use it, and offer transmission service to all eligible wholesale buyers and sellers. Order 889 created an open access same-time information system and implemented standards so employees engaged in transmission activities and employees engaged in wholesale market tasks functioned independently. Together, the two orders led to the development of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).

- 2005: NEPA was amended to authorize mandatory reliability standards and certify a reliability organization to enforce those standards; study transmission congestion and evaluate alternatives for constraints and congestion, including siting and incentives to alleviate problems; increase tax incentives for renewable energy development; and weaken PURPA "avoided-cost" purchase requirements in certain circumstances.

- 2007: The Energy Independence and Security Act changed lighting energy efficiency standards, allowed subsidized loans to certain facilities, and called for smart grid interoperability standards to be developed.

- 2009: The American Recovery and Reinvestment Act funded energy efficiency and infrastructure programs as well as research in the Department of Energy.

- 2011: FERC Order 1000 established new rules for interregional transmission planning and cost allocation for all public utility transmission providers and eliminated a federal right of first refusal in FERC tariffs and agreements.

In addition, environmental legislation and rulemaking have affected development of new electricity generation, including the: Clean Air Act (1970); National Environmental Policy Act (1970); Clean Water Act (1972); Resource Conservation and Recovery Act (1976); New Source Performance Standards (1979); Clean Air Act Amendments (1990); Cross-State Air Pollution Rule (2011); Mercury and Air Toxics Standards (2011); and Carbon Pollution Standards and Clean Power Plan (2015).

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APPENDIX NO. 36

Today in Energy, U.S. Energy Information Administration

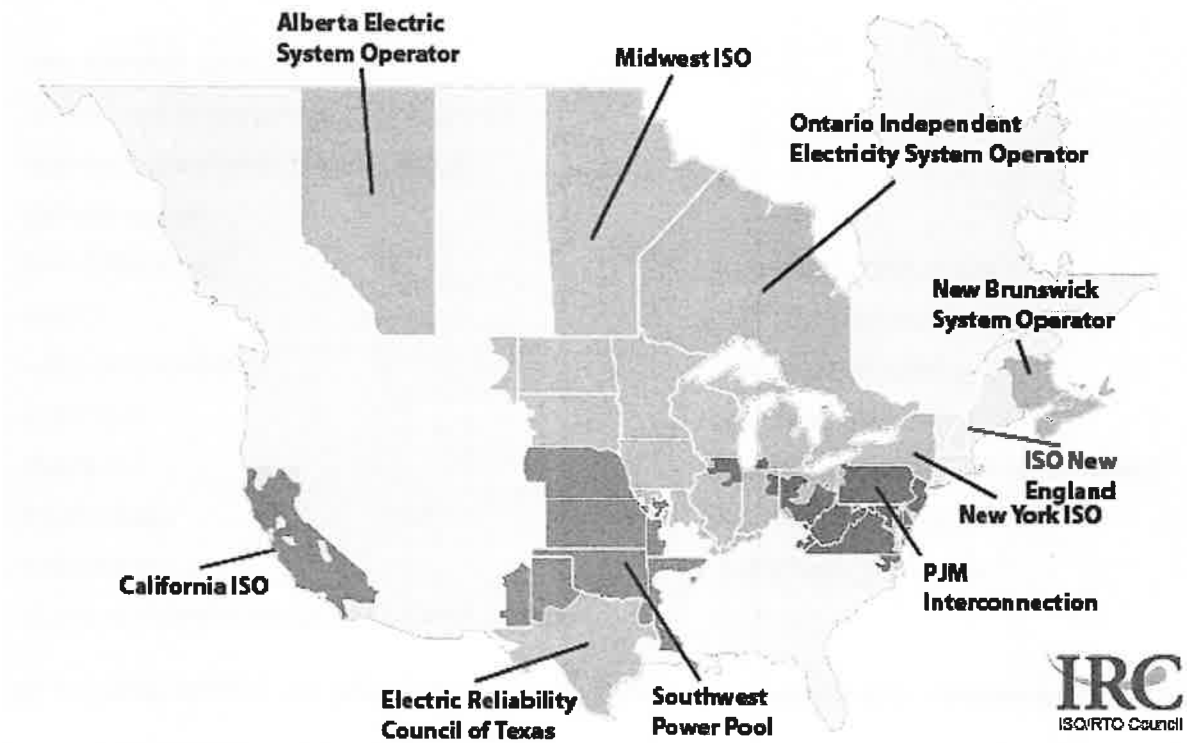
U.S. Energy Information Administration

Skip to sub-navigation

Today in Energy

April 4, 2011

About 60% of the U.S. electric power supply is managed by RTOs



Source: ISO/RTO Council

Published By: U.S. Energy Information Administration

Ten Regional Transmission Organizations (RTOs) operate bulk electric power systems across much of North America. RTOs are independent, membership-based, non-profit organizations that ensure reliability and optimize supply and demand bids for wholesale electric power. In 2009, U.S. RTOs managed 60% of the power supplied to load-serving entities. In other parts of the country, electricity systems are operated by individual utilities or utility holding companies.

RTOs first developed in the 1990's to accommodate the Federal Energy Regulatory Commission's (FERC) policy to encourage competitive generation through requiring open access to transmission. In the Northeast, the RTOs evolved from power pools that had coordinated utility operations for many decades. Elsewhere (the Midwest, California and Texas), RTOs

APPENDIX NO. 37

Transmission upgrades delivering substantial value for Southwest Power Pool members, SPP

January 26, 2016

January 26, 2016

Transmission upgrades delivering substantial value for Southwest Power Pool members

New study finds more than $240 million in annual fuel cost savings realized due to transmission investments during 2012-2014; Overall benefits expected to exceed $16.6 billion over 40 years

LITTLE ROCK, Ark. – Construction of electric transmission upgrades in the Southwest Power Pool (SPP) from 2012 to 2014 resulted in more than $240 million in fuel cost savings for utilities during the first year of operation of the company's wholesale energy market, according to a new study from the regional power grid operator.

The study analyzed the value provided by 348 transmission upgrades that involved almost $3.4 billion of capital investment.

Previous studies by SPP projected the expected future value of transmission construction based on latest available forecast data. This study used actual historical operating data obtained during the first year of operation of SPP's Integrated Marketplace to document transmission value already realized.

In addition to fuel cost savings, the study quantified other benefits associated with the transmission expansion upgrades, including reliability and resource adequacy benefits, generation capacity cost savings, reduced transmission losses, increased wheeling revenues and public policy benefits associated with more optimal wind development facilitated by the transmission upgrades. The net present value of all quantified benefits is expected to exceed $16.6 billion over a 40-year period, resulting in a benefit-cost ratio of at least 3.5. This means the investments are expected to produce more than $3.50 in overall benefits for every $1 in transmission-related costs.

"Transmission does more than just keep the lights on. It's an enabling resource that paves the way for numerous benefits to our stakeholders and their customers," said Nick Brown, president and CEO of SPP. "A modernized transmission system increases reliability, reduces costs by providing access to a wholesale energy market and effectively integrates wind and other renewable energy to the grid."

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Southwest Power Pool
201 Worthen Drive • Little Rock, AR 72223-4936
(501) 614-3200

APPENDIX NO. 38

Walton, R., “This is just the beginning.”

“The SPP Value of Transmission study is a path-beaking effort,” noted Johannes Pfeifenberger, Judy Chang and Onur Aydin of the Brattle Group in a letter accompanying the studyCompared to transmission planning studies, “it povides a more accurate estimate of the total benefits that a more robust and flexible transmission infrastructure provides to power marketers, market participants and, ultimately retail electric customers.”

The Brattle Group letter also added: “the estimated pesent value of the production cost savings in the SPP study likely is understated” due to several factors, including the fact that many of the major transmission projects evaluated were not yet in service during most of the period analyzed.

Read the study and the Brattle Group review at www.spp.org/value-of-transmission.

About Southwest Power Pool, Inc.

Southwest Power Pool, Inc. manages the electric grid and wholesale energy market for the central United States. As a regional transmission organization, the nonprofit corporation is mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power adequate transmission infrastructure and competitive wholesale electricity prices. Southwest Power Pool and its diverse group of member companies coordinate the flow of electricity across 56,000 miles of high-voltage transmission lines spanning 14 states. The company is headquartered in Little Rock, Ark. Learn more at www.spp.org.

Derek Wingfield, 501-614-3394, dwingfield@spp.org

UTILITY DIVE

DIVE BRIEF

'This is just the beginning': Southwest Power Pool begins operating Western imbalance market

Published Feb. 2, 2021

Robert Walton
Reporter

Dive Brief:

- Southwest Power Pool (SPP) on Monday began operating its new Western Energy Imbalance Services (WEIS) market, kicking off the real-time balancing market with a half dozen regional utilities participating.
- The WEIS has been in the works for more than a year, and SPP says many of the participants are now evaluating full membership in the SPP regional transmission organization (RTO). A Brattle study last year concluded adding members could produce $49 million in annual savings for consumers and SPP.
- Utilities joining the WEIS say the new service will help accelerate their decarbonization goals. There are concerns from some clean energy advocates, however, that SPP's new market creates a transmission seam across Colorado and may not be as efficient as a single RTO serving the state.

Dive Insight:

The launch of SPP's new balancing market will help participating utilities supply cleaner, cheaper energy, but Colorado is now served by two grid authorities and it remains to be seen if this is the most efficient method, according to Amanda Ormond, WAPA Administrator and CEO Mark Gabriel. The SPP market can help address those challenges.

"We have said for years that markets are coming to the West," Gabriel said in a statement. "We are now realizing those predictions across the interconnection first in the form of energy imbalance markets, which will benefit our customers and their consumers by meeting real-time fluctuations in demand."

SPP previously operated an imbalance market from 2007 to 2014, and officials say that market saved participants about $100 million in its first year of operation. The grid operator has cautioned it is too soon to know what savings the new WEIS will produce. SPP said that like its previous markets, the WEIS will "provide price transparency of wholesale energy, allow parties to trade bilaterally and hedge against costly transmission congestion."

And if SPP expands its full membership to include Basin Electric Power Cooperative, MEAN, Tri-State Generation and Transmission Association and WAPA, the grid operator says it will be able to grow the services and savings it provides.

"I'm hopeful this is just the beginning of valuable partnerships between SPP and western utilities that will help them and the customers they serve meet their financial, reliability and renewable-energy goals," SPP President and CEO Barbara Sugg said in a statement.

Along with the new WEIS, SPP said it offers other services to utilities under its Western Energy Services umbrella. In 2019, SPP launched its Western Reliability Coordination service. And last year, the grid operator was hired to be the program developer for the Northwest Power Pool's regional Resource Adequacy Program.

APPENDIX NO. 39

Texas grid vulnerable to blackouts during severe winter weather, even with new preparations, ERCOT estimate shows

Nov. 20, 2021

MENU

Texas grid vulnerable to blackouts during severe winter weather, even with new preparations, ERCOT estimates show

The most severe scenario considered by ERCOT for this winter — very high demand for power, extensive fossil fuel outages, and low renewable power production — does not capture the amount of power lost during February.

BY **ERIN DOUGLAS** NOV. 20, 2021 3 PM CENTRAL

COPY LINK

Snow surrounds an Austin Energy station on Feb. 18. Sergio Flores for The Texas Tribune

Sign up for The Brief, our daily newsletter that keeps readers up to speed on the most essential Texas news.

Electricity outages in Texas could occur this winter if the state experiences a cold snap that forces many power plants offline at the same time as demand for power is high, according to an analysis by the Electric Reliability Council of Texas. The outages could occur despite better preparations by power plants to operate in cold weather.

Heading into the winter, ERCOT considered five extreme scenarios in a risk assessment of the state's power supply. The grid operator estimates both how much electricity Texans are expected to demand and how much electricity power plants are expected to produce ahead of each season.

Following the widespread February power outages that left millions without electricity for several days, ERCOT changed those assessments to calculate what would happen if extreme conditions occurred simultaneously — like what happened this year.

The calculations show the power grid's vulnerability to the cumulative impact of multiple pressures that could leave the system short of a significant amount of power. Power grids must keep supply and demand in balance at all times. When Texas' grid falls below its safety margin of 2,300 megawatts of extra supply, ERCOT, the grid operator, starts taking additional precautions to avoid blackouts, such as asking residents to conserve power.

The calculations for severe risk this winter show that it wouldn't take a storm as bad as the one in February, when hundreds of people died, to take the grid offline.

The most severe scenario considered by ERCOT for this winter — very high demand for power, extensive natural gas and other fossil fuel outages, and excessively low renewable power production — still does not capture the amount of power lost during February. For two days in February, Texas averaged 34,000 megawatts of outages, according to a recent federal report on the crisis. ERCOT's seasonal assessment for this winter estimates that the state, in the worst case scenario, could have only about 10,000 to 19,000 megawatts of total outages at any one time, assuming better preparation by power plants for this winter as opposed to last.

"As part of our comprehensive planning, we also reviewed a number of low-probability, high-impact scenarios," said Chris Schein, a spokesperson for ERCOT, in a statement. "Generators across the state have made improvements in power plant weatherization."

Regulators in October finalized a rule that requires power plants to use "best efforts" to ensure plants can operate this winter and requires them to fix "acute" issues from the February 2021 winter storm.

ERCOT also estimated that Texans would demand, at most, about 73,000 megawatts of electricity at any given time, based on weather from a decade ago in 2011 and economic forecasts for 2020. But during the February power crisis, experts estimate that Texans needed about 77,000 megawatts to keep the power on.

"We've had years of poor planning of peak [demand] by ERCOT," said Alison Silverstein, an expert on Texas' electricity system who formerly worked at the Federal Energy Regulatory Commission and the Public Utility Commission of Texas. She spoke during a public event hosted by the environmental group the Sierra Club on Saturday. "ERCOT's power market has historically been managed to minimize costs, not to assure excellent reliability."

Four of the five extreme risk scenarios ERCOT considered would leave the grid short a significant amount of power, which would trigger outages for residents.

The extreme scenarios have a low chance of occurring, ERCOT emphasises in its report, and the grid operator estimates more power generation will be available than last winter.

Under typical winter grid conditions, the ERCOT report said, there will be sufficient power available to serve the state.

APPENDIX NO. 40

Wind Energy in Nebraska
American Wind Energy Association
(AWEA)

WIND ENERGY IN NEBRASKA

Wind energy means economic development for Nebraska.

Nebraska stands out as an emerging wind powerhouse. Nebraska now has over 2,300 MW of installed wind power and ranks 12th in the nation for installed capacity, with a total capital investment of over $3.8 billion. In 2019, wind power generated 19.9 percent of Nebraska's electricity, ranking 7th in the nation for wind energy as a share of total electricity generation. Harnessing more of Nebraska's wind potential could make the state a powerhouse for the wind industry while providing savings for electricity customers.

BENEFITS

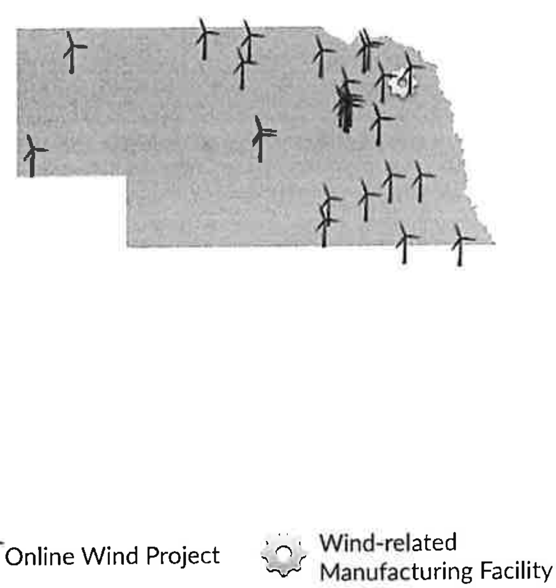
Jobs & Economic Benefits

The U.S. wind industry is a major economic development driver. In addition to job creation and billions of dollars in project investment, the wind industry invests heavily in local communities, providing significant revenue in the form of property, state, and local taxes.

- Direct wind industry jobs in 2019: **2,001 to 3,000**
- Capital investment in wind projects through 2019*: **$3.8 billion**
- Annual state and local tax payments by wind projects**: **$12 million**
- Annual land lease payments: **$14.7 million**

*Based on state and national averages from LBNL, NREL.

**Based on member data. Includes PILOT payments.



Wind-Related Manufacturing

Over 500 manufacturing facilities in the U.S. make products for the wind industry, from blades, towers, and turbine nacelles to raw components such as fiberglass and steel.

- Number of active manufacturing facilities in the state: **1**

STATE WIND FACTS

Wind Projects as of Q2 2020

- Installed wind capacity: **2,364 MW**
  - » State rank for installed wind capacity: **12th**
- Number of wind turbines: **1,127**
  - » State rank for number of wind turbines: **15th**
- Wind projects online: **27** (Projects larger than 10 MW: 20)
- Wind capacity under construction: **773 MW**
- Wind capacity in advanced development: **200 MW**

Wind Generation

In 2019, wind energy provided **19.90%** of all in-state electricity production.

- State rank for share of electricity: **7th**
- Equivalent number of homes powered by wind in 2019: **680,200**

Wind Energy Potential

- Land-based technical wind potential at 80 m hub height: **465,474 MW**

(Source: AWS Truepower, NREL)

Environmental Benefits

Wind energy reduces emissions and water consumption by avoiding generation from fossil-fuel power plants.

- In-state carbon dioxide emissions avoided in 2019*: **1.4 million metric tons**
  - » Equivalent cars' worth of emissions avoided: **290,000**
- In-state water consumption savings in 2019**: **715 million gallons**

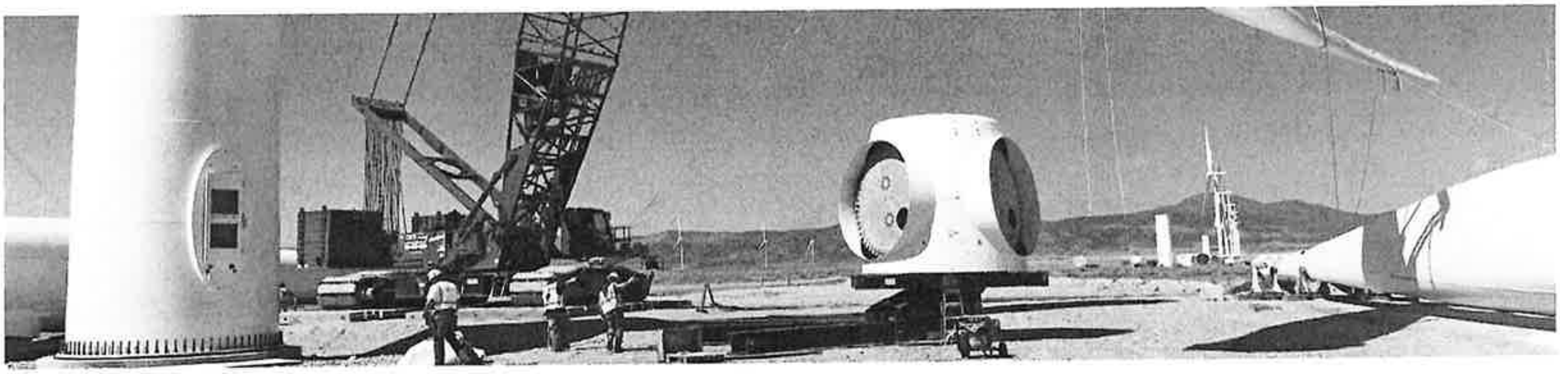
*Estimated using Aurora power sector model.

**Based on national average water consumption factors for coal and gas plants.

POLICY

Nebraska

The state of Nebraska does not currently have a renewable portfolio standard or goal set in place to require utilities to generate a certain percentage of electricity from renewable sources.



APPENDIX NO. 41

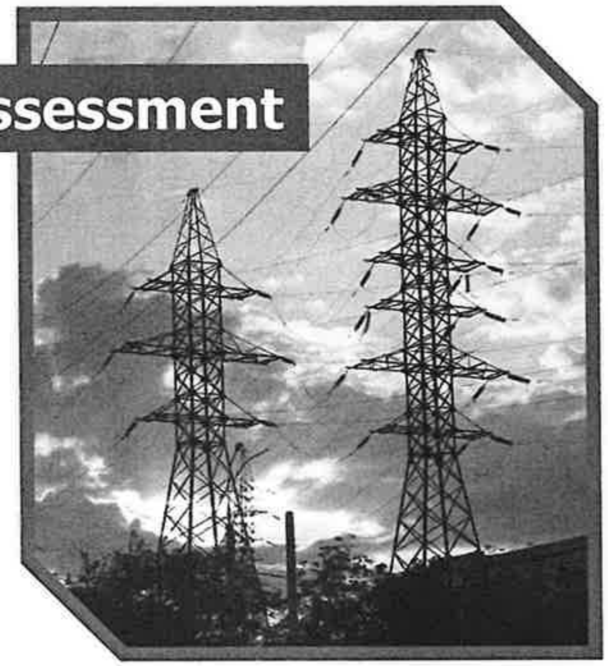
NERC

LONG TERM RELIABILITY ASSESSMENT (LTRA)

December 2021

Entire Report available in office of Natural Resources Committee

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION



2021 Long-Term Reliability Assessment

December 2021

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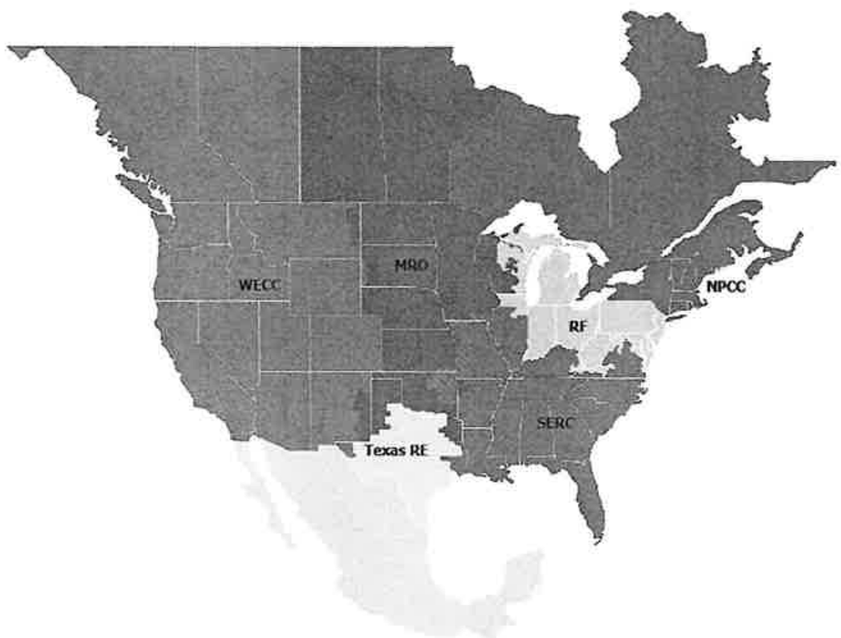
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (RE), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one RE while associated Transmission Owners/Operators participate in another. A map and list of the assessment areas can be found in the **Regional Assessments** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, serving more than 334 million people. Section 39.11(b) of the U.S. FERC's regulations provide that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information collected by NERC from the six REs on an assessment area basis to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2021 about known system changes with updates incorporated prior to publication. The assessment period for this *2021 LTRA* includes projections for 2022–2031; however, some figures and tables examine data and information for the 2021 year. The assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in **Demand Assumptions and Resource Categories**. Reliability impacts related to physical and cyber security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through the Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electricity industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data and information from each RE are also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each RE, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

In this *2021 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2021. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each RE's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

In April 2020, NERC published its *Special Report Pandemic Preparedness and Operational Assessment: Spring 2020* to advise electricity stakeholders about elevated risk to electric reliability as a result of the global health crisis.[7] NERC continues to assess risks to the reliability and security of the BPS from the global health crisis and reports on industry actions and preparedness in this *LTRA*.

Reading this Report

This report is compiled into two major parts:

- Reliability Assessment of the North American BPS
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- Regional Reliability Assessment
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

[7] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Pandemic_Preparedness_and_Op_Assessment_Spring_2020.pdf

Executive Summary

This *2021 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten years. The *LTRA* also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS.

Governmental policies, changes in comparative resource economics, and customer demand for clean energy are driving the rapidly changing resource mix within the BPS; the BPS has already seen a great deal of change and more is underway. Managing this pace of change presents the greatest challenge to reliability. As the system transitions, changing weather systems present new challenges and fuel becomes inherently less secure. The FERC, NERC, and RE staff report—*The February 2021 Cold Weather Outages in Texas and South Central United States* (*The February 2021 Cold Weather Outages Report*)—highlighted the deadly impacts of these risks if reliability is not prioritized in BPS resource planning and policy considerations.[8]

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.

This *2021 LTRA* identifies numerous risks that stakeholders and policymakers need to focus on over the next ten years. While this assessment calls out the assessment areas in the U.S. Western Interconnection and MISO for resource adequacy and energy sufficiency concerns, all Interconnections face reliability challenges. Key findings and recommendations are summarized as follows.

Resource Adequacy and Energy Risks

Most areas are projecting to have adequate resource capacity to meet annual peak demand associated with normal weather. Capacity shortfalls, where they are projected, are the result of future generator retirements that have yet to be replaced with new resource capacity. Capacity-based estimates, however, can give a false indication of resource adequacy. Energy risks emerge when variable energy resources (VER) like wind and solar are not supported by flexible resources that include sufficient dispatchable, fuel-assured, and weatherized generation:

- 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.
- In the **California-Mexico (CA/MX) part of WECC**, the planned retirement of the Diablo Canyon Power Plant contributes to declining reserve margins in the area beginning in 2026. However, energy risks are present today as electricity resources are insufficient to manage the risk of load loss when wide-area heat events occur. Risk is most acute in late afternoon since there are energy limitations as solar photovoltaic (PV) resource output diminishes. Energy analysis shows up to 10 hours of load loss beginning in 2022 and as much as 75,000 MWh of unserved energy in extreme conditions in 2024. Flexible resources that can be dispatched to counter solar PV behavior and be relied upon with assured fuel supplies are needed to reduce the load-loss risk and serve energy demand in all seasons and time periods. Recent California Public Utilities Commission actions to boost capacity at the Aliso Canyon natural gas storage field is an encouraging step toward firming up fuel for flexible generation capacity in California.
- The **U.S. Northwest and Southwest parts of WECC** have increasingly variable resource profiles, raising the risk of energy shortfalls. Energy analysis indicates 23 load-loss hours in the Northwest in 2022. The Southwest also faces potential load-loss hours beginning in 2024. As resource planners in parts of the Western Interconnection turn increasingly to external transfers for sufficient capacity and energy to meet demand, the need for regional coordination and resource adequacy planning is growing.

[8] https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

SPP Assessment

The ARMs do not fall below the Reference Margin Level of 16% (SPP coincident) for the entire 10-year assessment period. The Reference Margin Level is determined by a probabilistic LOLE study. The SPP assessment area performs a biennial LOLE study to establish PRMs. Determination of the PRM is supported by a probabilistic LOLE study, which will analyze the ability to reliably serve the SPP BA area's 50/50 forecasted peak demand by utilizing a security-constrained economic dispatch. SPP, with input from the stakeholders, develops the inputs and assumptions used for the LOLE study. SPP will study the PRM such that the LOLE for the applicable planning year (two- and five-year study) does not exceed one day in ten years, or 0.1 day per year. At a minimum, the PRM will be determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year.

SPP load peaks during the summer season; the 2021 load forecast is projected to peak at 50,986 MW, which is projected to decrease compared to the previous year's LTRA forecast for the 2020 summer season. The coincident peak for the SPP assessment area is projected to decrease based on the member-submitted peak forecast being lower than the previous year along with approximately 250 MW of load transferring to ERCOT. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. The current annual growth rate is approximately 0.1%.

SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area.

SPP currently has approximately 250 MW of installed solar generating facilities. The SPP Model Development, Economic Studies, and the Supply Adequacy working groups are currently developing policies and procedures around DERs. The SPP Resource Adequacy Working Group implemented policies for DERs in 2020 that require certain testing, reporting, and documents for resources and programs not registered in the SPP integrated market.

Since the *2020 LTRA*, more than 1,500 MW of nameplate capacity has been retired in SPP. The generation that has been retired over the past year has mainly been replaced with wind resources. The impact of retirements to resource adequacy is assessed in the LOLE study. Currently, SPP is not expecting any long-term reliability impacts resulting from generating plant retirements, but will evaluate these impacts in the 2021 LOLE study.

The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinates the modeling of transfers between PC footprints. The modeled transactions are fed into the models created for the SPP planning process.

During April 2019, SPP and ERCOT executed a coordination plan that superseded the prior coordination agreement. The coordination plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers, and switchable generation resources. Under the terms of the coordination plan, SPP has priority to recall the capacity of any switchable generation resources that have been committed to satisfy the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff.

Annually, SPP and ERCOT update the coordination plan based on the latest discussions and business decisions.

The SPP board of directors approved the *2020 Integrated Transmission Plan Assessment* and the *2020 SPP Transmission Expansion Plan Report*. Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users.