BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2210

In the Matter of Idaho Power Company, Application for Waiver of Competitive Bidding Rules	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION'S COMMENTS

I. INTRODUCTION

The Northwest & Intermountain Power Producers Coalition ("NIPPC") hereby respectfully submits these comments on Idaho Power Company's ("Idaho Power's") Application for Waiver of Competitive Bidding Rules ("Waiver Application")[1] and in response to Staff's Report recommending denial of Idaho Power's waiver request because good cause does not exist.[2] As explained below, NIPPC supports Staff's recommendation and recommends that the Oregon Public Utility Commission (the "Commission" or "OPUC") deny Idaho Power's Application for Waiver of Competitive Bidding Rules. Generally, NIPPC is not opposed to limited waiver requests and is flexible if legitimate waiver is necessary; however, NIPPC is opposed to outright waivers of all the substantive competitive bidding rules when it is clear the utility is demonstrating it wants to seek utility-owned resources and the practical result is an RFP

1 Application for Waiver of Competitive Bidding Rules (Dec. 9, 2021) [hereinafter "Waiver Application"].

2 Staff Report at 1 (Mar. 2, 2022).

that lacks transparency, is not understandable, and is unfair. Granting Idaho Power's Waiver Application would harm competition and not align with the goals of the competitive bidding rules. Thus, the Commission should deny Idaho Power's Waiver Application.

At the same time, NIPPC recognizes that flexibility and expediency in the procurement review process can be valuable as market developments and state policies shift. NIPPC does not reject out of hand that wholesale power markets are materially affected by the accelerating retirement of dispatchable capacity resources in the Northwest, increasing global supply chain issues causing project delays, and the time-limited federal clean energy tax credit opportunities. Given these factors, NIPPC is open to exploring appropriate ways that enable Idaho Power to procure critically needed resources in time and ensure a robust and competitive solicitation.

II. BACKGROUND

Idaho Power submitted its Waiver Application on December 9, 2021. The Staff Report includes an excellent summary of the background of the Waiver Application, and these comments only emphasize two additional items.

Around the same time of the Waiver Application, Idaho Power submitted a similar request at the Idaho Public Utilities Commission ("IPUC").[3] The filing before the IPUC provides more clarity regarding the utility's goals with the Waiver Application than

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3 *See generally in re Idaho Power's Application for Authority to Proceed with Resource Procurements to Meet Identified Capacity Deficiencies in 2023, 2024, and 2025 to Ensure Adequate, Reliable, and Fair-Priced Service to Its Customers*, IPUC Docket No. IPC-E-21-41, Application (Dec. 3, 2021). The IPUC Application is attached as Attachment A.

it included in its Oregon filing. The IPUC requires Idaho Power to comply with the Oregon competitive bidding rules, and Idaho Power is asking the IPUC to eliminate this requirement. In the IPUC Waiver Application, Idaho Power requested that the IPUC issue an order:

> (1) eliminating the IPUC requirement to comply with the Public Utility Commission of Oregon ("OPUC") resource procurement rules in favor of a competitive, but expedited process; (2) authorizing Idaho Power to move forward expeditiously with resource procurements to meet identified generation resource needs in 2023, 2024, and 2025; and (3) *affirming support and the continuation of the state of Idaho's system of public utility regulation under which the interests of customers are best served by a vertically integrated electric utility maintaining ownership of the necessary generation, transmission and distribution utility functions, with limited exceptions*.[4]

Idaho Power is specifically asking the IPUC to support Idaho Power's acquisition of utility-owned resource for the purpose of maintaining "a vertically integrated electric utility." Idaho Power is doing this because, according to Idaho Power, "the interests of customers are best served" when customers are served from utility owned resources and not from purchases of third-party resources through power purchase agreements. Essentially, Idaho Power wants to waive the competitive bidding rules so that it does not need to purchase from independent power producers. NIPPC disagrees that this would "best serve" customers; instead, it would have a negative effect on competitive procurement and harm customers.

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4 IPUC Docket No. IPC-E-21-41, Application at 1-2 (emphasis added). Note that the third reason was left out of the OPUC Waiver Application.

Shortly after filing the Waiver Application, Idaho Power issued a Notice of Intent for a 2022 Request for Proposals ("2022 RFP") on December 21, 2021 seeking completed notice of intent forms from interested parties by December 23, 2021.[5] This was during the holidays and only provided a roughly two-day turnaround to notify Idaho Power if a project intended to submit a bid into the 2022 RFP. There was no practical opportunity for most bidders to submit a notice of intent, and no ability for stakeholders to challenge the 2022 RFP process. This remarkable exercise by Idaho Power suggests that the state commissions must remain in the role of ensuring that the utility takes competitive procurement seriously.

NIPPC notes that in principle it is not opposed to waiving certain competitive bidding rules or expediting the RFP process, when justified. For example, PacifiCorp recently sought and obtained a waiver of the Oregon rule requiring a utility to include the scoring and associated modeling methodology prior to preparing a draft RFP.[6] The waiver allowed the RFP to move forward more quickly and better align with the generator interconnection queue reform filing at the Federal Energy Regulatory Commission. The waiver was reasonable based on the specific circumstances, including that all stakeholders were still provided a full opportunity to comment on the scoring and modeling methodologies.

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5 *See* Idaho Power, Request for New Resources Notice of Intent: Questions and Answers (Dec. 22, 2021). The document is attached as Attachment B.

6 *In re PacifiCorp, dba Pacific Power Application for Approval of 2020 All-Source Request for Proposal*, Docket No. UM 2059, Order No. 20-114, Appendix A at 1, 8, 10-12 (Apr. 8, 2020).

If Idaho Power had proposed a more limited waiver request that sought to expedite the RFP, then NIPPC likely could have supported the waiver or proposed specific conditions upon the waiver request. NIPPC, however, supports Staff recommendation to deny the waiver request because, under the waiver, the core competitive bidding provisions that ensure a fair, transparent, and understandable RFP are completely absent. NIPPC encourages Idaho Power to work with stakeholders to chart a path forward to meet its need to serve its load while also ensuring competition, including potentially filing an updated request for a more limited and appropriately tailored waiver.

III. COMMENTS

A. Legal Standard

The Commission's competitive bidding rules apply when an electric utility seeks to acquire resources or a contract for more than an aggregate of 80 megawatts and five years in length.[7] The Commission can waive any of the competitive bidding rules upon request or its own motion if good cause is shown.[8] The Oregon administrative rules do not clearly identify a standard for finding good cause that would allow for a waiver of the competitive bidding rules, but Staff has identified three criteria to evaluate good cause: 1) minimization of long-term costs and risks; 2) whether the resource or contract

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7 OAR 860-089-0010(1) ("The rules contained in this Division apply to electric companies, and are intended to provide an opportunity to minimize long-term energy costs and risks, complement the integrated resource planning (IRP) process, and establish a fair, objective, and transparent competitive bidding process, without unduly restricting electric companies from acquiring new resources and negotiating mutually beneficial terms.").

8 OAR 860-089-0010(2).

complements the integrated resource planning ("IRP") process; and 3) whether acquisition of the resource or contract can be conducted in a manner that is "transparent, understandable, and fair."[9] These are essentially the same requirements that are the goals of the competitive bidding rules,[10] and NIPPC agrees that they are the appropriate standards to evaluate a waiver request under.

While Idaho Power is not seeking an exception at this time, a utility is not required to comply with the competitive bidding rules if an exception applies.[11] The exceptions are:

> (a) There is an emergency; meaning a human-caused or natural catastrophe resulting from an unusual and unexpected event, including but not limited to earthquake, flood, war, or a catastrophic energy plant failure, that requires an electric company to take immediate action;
> (b) There is a time-limited opportunity to acquire a resource of unique value to the electric company's customers;
> (c) An alternative acquisition method was proposed by the electric company in the IRP and explicitly acknowledged by the Commission; or
> (d) Seeking to exclusively acquire transmission assets or rights.[12]

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9 Staff Report at 5 (citing *In re Portland General Electric Company Application for Waiver of the Competitive Bidding Rules*, Docket No. UM 2176, Order No. 21-328, Appendix A at 6 (Oct. 6, 2021)). Staff summarizes the Order as: "The Commission adopted Staff's recommendation to grant PGE a waiver to the [competitive bidding rules], which was based on the logic that PGE's good cause reasoning met the evaluation criteria established by Staff." *Id.* at 5 n.17.

10 OAR 860-089-0100(1).

11 OAR 860-089-0100(3).

12 OAR 860-089-0100(3)(a)-(d).

Within 30 days of seeking to acquire a resource under one of the exceptions above, the utility must file a report with the Commission justifying the acquisition under an exception.[13]

B. Good Cause Does Not Exist to Grant Idaho Power's Waiver Application

NIPPC agrees with Staff that good cause does not exist to grant Idaho Power's Waiver Application.[14] Staff summarizes Idaho Power's good cause argument into three assertions:

> 1. Due to various and previously unforeseen reasons, the Company has an urgent need for new resources, which cannot be acquired in a timely enough fashion using Oregon's [competitive bidding rules ("CBRs")]
> 2. Idaho Power's proposed alternative process achieves the broad goals of CBR.
> 3. There is value to the Company if a single regulatory process for this resource procurement and given Idaho Power's unique, split territory – with only 5 percent of its load in Oregon – the Company prefers the use an alternative process based on the Idaho Commission's [Certificate of Public Convenience and Necessity] process.[15]

NIPPC agrees with Staff that these assertions do not show good cause to grant Idaho Power's Waiver Application.

1. Idaho Power's Changes in IRP Modeling Do Not Justify Waiving the Competitive Bidding Rules as Idaho Power's Waiver Requests

In anticipation of Idaho Power's next IRP, Idaho Power made changes to how its IRP model calculated load and resource balance and planning reserve margins.[16] Idaho

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13 OAR 860-089-0100(4).
14 Staff Report at 5-7, 9.
15 Staff Report at 5.
16 *See* Waiver Application at 6-7, 8-10.

Power claims these changes in modeling have contributed to Idaho Power's accelerated capacity need.[17] NIPPC agrees with Staff that changes in modeling methodology that have not been vetted by any stakeholders or approved by the Commission do not justify granting a waiver of competitive bidding rules.[18] NIPPC is not challenging the actual changes to the modeling, but believes that Idaho Power should go through the right process before waiving all of the Commission's meaningful competitive bidding rules. Idaho Power has complete control over its models and there is no reason why Idaho Power could not have made the changes and notified the Commission and stakeholders earlier. Stakeholders have not had an opportunity to examine Idaho Power's new modeling methodologies, ask questions about the methodology, or vet the accuracy of the new modeling methodology.[19] All of this should occur before Idaho Power's new and unilaterally developed modeling methodology should be a factor in consideration of waiving the competitive bidding rules. Thus, an accelerated capacity need because of changes in modeling methodologies does not demonstrate good cause to grant Idaho Power's Waiver Application.

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17 *See* Waiver Application at 5.

18 Staff Report at 6.

19 *See, e.g., In re Idaho Power 2021 IRP*, Docket No. LC 78, Staff email to Idaho Power regarding draft IRP (Dec. 27, 2021) ("We appreciate that Idaho Power is sharing its 2021 IRP Draft for review prior to filing before the end of the year. … However, providing four business days for review over the holidays, during which time many staff take additional time off, does not provide sufficient time for staff to plan for and conduct this review. … It is unfortunate that we, and we imagine others of the public, won't have a meaningful review and comment opportunity for the 2021 IRP."); *see also* Docket No. LC 78, Motion for Waiver under OAR 860-082-0400(1) and Extension of Time (Feb. 17, 2022) (Staff's request for the deadline for opening comments to be extended to October 17, 2022 in light of Idaho Power's incomplete filing and other reasons).

2. Idaho Power's Creation of its Own Timing Dilemma Does Not Justify Waiving the Competitive Bidding Rules

Idaho Power reasons that its Waiver Application should be granted because the Oregon RFP process is too lengthy to meet Idaho Power's capacity needs in 2023, 2024, and 2025.[20] NIPPC has not opposed in the past, and is not opposed now, to more limited and well supported waiver requests that expedite the review of this or other RFPs. However, NIPPC agrees with Staff that Idaho Power could have started the RFP process earlier in order to comply with Oregon's competitive bidding rules.[21] Idaho Power had complete control over when it decided to start the RFP process (just as it had control of modifying and running its models), and poor planning on Idaho Power's part does not necessitate an emergency on the part of the Commission, Staff, or stakeholders.

In May 2021, Idaho Power indicated its near-term capacity needs had accelerated and that it would need capacity much sooner.[22] However, Idaho Power was aware of this capacity need even sooner than May 2021.[23] Thus, Idaho Power could have begun the RFP in early 2021 instead of December 2021. If Idaho Power had started the RFP process in mid-2021, then there would have been adequate time to conduct the RFP process in accordance with Oregon competitive bidding rules and acquire resources to meet its 2023 capacity needs.

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20 Waiver Application at 15-17.

21 Staff Report at 6.

22 Waiver Application at 6-7.

23 Staff Report at 3, n.10 ("While this new deficit was officially confirmed in May 2021 as part of the completed Valmy Unit 2 reliability and economic impact analysis, per Information Request #7 Idaho Power had known of this deficit since early 2021. In February and April 2021 Idaho Power had shared this information with its IRP Advisory Council.").

Idaho Power should not be able to skirt the competitive procurement process and subject ratepayers to cost risks because it chose not to begin the RFP process earlier. Thus, Idaho Power's self-generated timing dilemma does not demonstrate good cause to grant Idaho Power's Waiver Application. NIPPC is not opposed to considering evidence of a capacity need that in fact could not have been anticipated in the first half of 2021, but Idaho Power has not adequately made such a case.

3. Idaho Power's Proposed Alternative Process Does Not Achieve the Broad Goals of the Competitive Bidding Rules

Idaho Power's Waiver Application should be denied because Idaho Power's proposed alternative process does not achieve the broad goals of the competitive bidding rules. Oregon's competitive bidding rules are "intended to provide an opportunity to minimize long-term energy costs and risks, complement the integrated resource planning (IRP) process, and establish a fair, objective, and transparent competitive bidding process, without unduly restricting electric companies from acquiring new resources and negotiating mutually beneficial terms."[24] One of the Commission's purposes of adopting the competitive bidding rules was "reducing the [utility ownership] bias through our competitive bidding guidelines."[25] Idaho Power's proposed alternative process does not align with these goals.

Idaho Power asserts that its 2022 RFP "will be generally consistent with the 2021 RFP in terms of the evaluation and scoring of bids."[26] Idaho Power states it will use

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24 OAR 860-089-0010(1).

25 *In re OPUC Investigation Regarding Competitive Bidding*, Docket No. UM 1182, Order No. 14-149 at 1 (Apr. 30, 2014).

26 Waiver Application at 13.

Black & Veatch Management Consulting, LLC to assist in the development of the RFP and evaluation of bids.[27] Idaho Power states it intends to file a request for acknowledgement of the selected resources similar to how it will file for a certificate of public convenience and necessity process in Idaho.[28]

The most important elements of the competitive bidding rules designed to minimize long-term costs and risk and increase transparency, fairness, and objectivity that Idaho Power's alternative process are completely absent. These include:

- Use of an Independent Evaluator at several key stages in the RFP process.[29]
- Review of Benchmark bids prior to other bids.[30]
- Public input and Commission approval of scoring and modeling methodology.[31]
- Public input and approval of the RFP.[32]
- Bidder ability to self-score.[33]
- Use of the IRP model to analyze and test RFP projects against sensitivities.[34]
- Consideration of whether Benchmark bid elements will be made available to all bidders.[35]
- Full access by Commission and Independent Evaluator to all models and sensitivity analyses.[36]

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27 Waiver Application at 13.
28 Waiver Application at 18-19.
29 OAR 860-089-0450; *see also* Docket No. UM 1182, Order 14-149, Appendix A at 2, 4.
30 OAR 860-089-0350(1); *see also* Docket No. UM 1182, Order 14-149, Appendix A at 3.
31 OAR 860-089-0250(2).
32 OAR 860-089-0250, -0500; *see also* Docket No. UM 1182, Order 14-149, Appendix A at 2, 5
33 OAR 860-089-0400(2)(b).
34 OAR 860-089-0400(5)-(6).
35 OAR 860-089-0300(2)-(3).
36 OAR 860-089-0400(6); *see also* Docket No. UM 1182, Order 14-149, Appendix A at 3.

This list is not exhaustive and simply highlights some of the key competitive procurement requirements not found in Idaho Power's proposed alternative process. Even without addressing Idaho Power's openly stated preference (in its analogous filing in Idaho) for a utility owned resource as part of a vertically integrated utility, the lack of these requirements raises concerns about the transparency, fairness, and objectivity of the 2022 RFP. Further, there is greater risk of long-term cost and risks to ratepayers if the competitive bidding rules are waived. Thus, Idaho Power's proposed alternative does not achieve the broad goals of the competitive bidding rules and does not demonstrate good cause to grant Idaho Power's Waiver Application.

C. Exceptions Do Not Appear to Apply

NIPPC understands that a denial of a waiver request would not preclude Idaho Power from acquiring resources and filing an exception request. However, NIPPC notes that any proposed exception would require scrutiny. For example, there does not appear to be an emergency as Idaho Power could have filed the waiver request long before December 2021. Also, as Staff mentions, the only change in the IRP is modeling, which has not been vetted by stakeholders or acknowledged by the Commission. Finally, an RFP process could have been completed within a year, or still could be completed within a year to meet capacity need. Further, Idaho Power has not explained how "[t]here is a time-limited opportunity to acquire a resource of unique value to the electric company's customers."[37] While NIPPC has not seen evidence that an exception would apply, the Commission does not need to resolve this issue at this time and NIPPC reserves the right

[37] OAR 860-089-0100(3)(b).

to respond to any exception request filed in the future by Idaho Power. NIPPC underscores that it is not reflexively against appropriate ways to expedite the competitive procurement process in order to meet legitimate utility needs or market constraints.[38]

IV. CONCLUSION

For the reasons stated above, the Commission should deny Idaho Power's Application for Waiver of Competitive Bidding Rules without prejudice to Idaho Power filing a revised application for a partial waiver that still encourages meaningful competition in connection with the company's 2022 RFP.

Dated this 7th day of March 2022.

Respectfully submitted,

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[38] NIPPC notes that it is engaging through UM 2225 with, among other objectives and considerations in the proceeding, Staff's aspiration with respect to competitive procurement: "Rather than creating an example of how the CBRs can be waived based on rapidly changing market conditions, Staff hopes to work through HB 2021 implementation process in UM 2225 to establish a different path. Staff's aspiration is to improve and better harness Oregon's planning and competitive resource acquisition processes so the state can not only reach HB 2021's GHG reduction targets but also achieve the Legislation's policy goals around resiliency opportunities and the offsetting of fossil fuels with community-based renewables in the most cost-effective manner possible." Staff Report at 8.

Richardson Adams, PLLC

Gregory M. Adams
OSB No. 101779
515 N. 27th Street
Boise, Idaho 83702
Telephone: (208) 938-2236
Fax: (208) 938-7904
greg@richardsonadams.com

Sanger Law, PC

Irion A. Sanger
Ellie Hardwick
Sanger Law, PC
4031 SE Hawthorne Blvd.
Portland, Oregon 97214
Telephone: 503-756-7533
Fax: 503-334-2235
irion@sanger-law.com

Of Attorneys for Northwest &
Intermountain Power Producers Coalition

Attachment A

IPUC Docket No. IPC-E-21-41, Idaho Power's Waiver Application

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DONOVAN WALKER
Lead Counsel
dwalker@idahopower.com

December 3, 2021

VIA ELECTRONIC FILING

Jan Noriyuki, Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-21-41
In The Matter Of Idaho Power Company's Application For Authority to Proceed with Resource Procurements to Meet Identified Capacity Deficiencies in 2023, 2024, and 2025 to Ensure Adequate, Reliable, and Fair-Priced Service to its Customers

Dear Ms. Noriyuki:

Enclosed for electronic filing, please find Idaho Power Company's Application for Authority to Proceed with Resource Procurements in the above matter. Please feel free to contact me directly with any questions you might have about this filing.

Very truly yours,

Donovan E. Walker

Donovan E. Walker

DEW:cld
Enclosures

DONOVAN E. WALKER (ISB No. 5921)
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
Boise, Idaho 83707
Telephone: (208) 388-5317
Facsimile: (208) 388-6936
dwalker@idahopower.com

Attorney for Idaho Power Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO PROCEED WITH RESOURCE PROCUREMENTS TO MEET IDENTIFIED CAPACITY DEFICIENCIES IN 2023, 2024, AND 2025 TO ENSURE ADEQUATE, RELIABLE, AND FAIR-PRICED SERVICE TO ITS CUSTOMERS.	))))))))	CASE NO. IPC-E-21-41 APPLICATION FOR AUTHORITY TO PROCEED WITH RESOURCE PROCUREMENTS

Idaho Power Company ("Idaho Power" or "Company"), in accordance with *Idaho Code* §§ 61-501, 61-502, 61-503, 61-508, 61-526; as well as RP 52, and 112, hereby respectfully makes application to the Idaho Public Utilities Commission ("Commission" or "IPUC") for an order authorizing the Company to move forward with the procurement of capacity resources needed to provide adequate, reliable, and fair-priced service to customers. Idaho Power requests that the Commission issue an order: (1) eliminating the IPUC requirement to comply with the Public Utility Commission of Oregon ("OPUC") resource procurement rules in favor of a competitive, but expedited process; (2) authorizing Idaho Power to move forward expeditiously with resource procurements to meet identified generation resource needs in 2023, 2024, and 2025; and (3) affirming support and the continuation of the state of Idaho's system of public utility regulation under which the interests of customers are best served by a vertically integrated electric utility maintaining ownership of the necessary generation, transmission and distribution utility functions, with limited exceptions.

I. INTRODUCTION AND SUMMARY - A DYNAMIC ENERGY LANDSCAPE

Idaho Power has not added a supply-side, dispatchable resource since the Langley Gulch combined-cycle, natural gas combustion turbine, which was granted a Certificate of Public Convenience and Necessity ("CPCN" or "Certificate") in 2009.[1] Idaho Power's most recent Integrated Resource Plan ("IRP"), the Second Amended 2019 IRP, acknowledged by the Commission on March 16, 2021[2], does not show a first capacity deficit until the summer of 2028. However, during the preparation of the 2021 IRP that Idaho Power anticipates filing before the end of this year, an updated Load and Resource ("L&R") balance analysis in May 2021 identified a first capacity deficit of 78 megawatts ("MW") in June of 2023, growing each year through 2026, when the Boardman to Hemingway ("B2H") 500 kilovolt transmission line is expected to be operational. This rapid change in deficit position was caused by several dynamic and evolving factors including: third-party transmission constraints and changes to the assumptions in the L&R balance regarding available transmission capacity following the retirement of coal plants; the unavailability of import transmission capacity on the market; planning margin adjustments associated with incorporating Loss of Load Expectation ("LOLE") and Effective Load Carrying Capability ("ELCC") planning methodologies; increasing population and associated emergent demands on the Company's system; and the

[1] Case No. IPC-E-09-03, Order No. 30892

[2] Case No. IPC-E-19-19, Order No. 34959.

diminishing demand response ("DR") resource effectiveness and low solar generation effectiveness during critical demand hours. These factors and the dynamic energy landscape in which the Company is operating are discussed further in this Application.

Under Idaho law, Idaho Power has an obligation to provide adequate, efficient, just, and reasonable service on a nondiscriminatory basis to all those that request it within its certificated service area.[3] In order to meet its obligations to reliably serve customer load, and given the extremely short turn-around to construct a resource to meet a summer 2023 deficit, particularly in the midst of supply chain disruption,[4] ongoing COVID-19 impacts, and constraints in the industry and in ancillary industries, the Company is currently conducting a competitive solicitation through a Request for Proposals ("RFP") seeking to acquire up to 80 MW of company-owned resources to meet the 2023 capacity deficit - seeking projects to be online by June of 2023. The RFP contemplated wind, solar, energy storage, some combination of the forementioned resources, or other options to meet critical demand hours. Idaho Power is also, in parallel, investigating different configurations of Company owned and constructed battery storage systems, possible modifications to existing DR programs[5], and pursuing other short-term market solutions in attempts to meet the forecasted capacity deficits. However, this will not be enough to meet the rapidly evolving and dynamic forecasted capacity deficits.

In 2010, the Commission initiated a case[6] seeking to establish competitive bidding guidelines for the RFP process used to acquire supply-side resources by Idaho Power.

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[3] *Idaho Code* §§ 61-302, 61-315, 61-507.
[4] Idaho Power has seen the general supply chain disruption in its own supply chain which has increased timelines across the board. The Notice of Force Majeure received by Idaho Power from Jackpot Holdings is based upon and also evidences the wide-spread nature and uncertainty in the current environment regarding third parties' ability to deal with such issues even when needed to meet their firm contractual commitments. See generally, *How the Supply Chain Broke, and Why It Won't Be Fixed Anytime Soon*, Peter S. Goodman, New York Times, Oct. 31, 2021. Supply Chain Shortages: Your Questions Answered - The New York Times (nytimes.com)
[5] IPC-E-21-32
[6] Case No. IPC-E-10-03.

In 2013, the Commission closed this case without establishing Idaho-specific resource procurement guidelines, but rather directed Idaho Power to follow the RFP guidelines applicable in its Oregon service area. The Oregon RFP guidelines to which the Commission referred were later codified into the administrative rules of the OPUC. OAR 860-089-0010 *et. seq.* ("OPUC Resource Procurement Rules"). The OPUC Resource Procurement Rules impose competitive bidding requirements upon an electric utility for the "acquisition of a resource or a contract for more than an aggregate of 80 megawatts and five years in length," among other requirements. OAR 860-089-0100(1)(a). There are certain exceptions to the applicability of the OPUC Resource Procurement Rules, including the exception used for executing the Jackpot Solar power purchase contract:[7] "There is a time-limited opportunity to acquire a resource of unique value to the electric company's customers." OAR 860-089-0100(3)(b). The OPUC Resource Procurement Rules also contain an exception to their applicability based upon the OPUC acknowledging an alternative acquisition method in the utility's IRP. OAR 860-089-0100(3)(c). What the OPUC Resource Procurement Rules do not contain, however, is an exception or exemption from the lengthy procurement process for when a utility identifies a critical and time-sensitive need to obtain capacity resource to reliably serve load.

While the 80 MW RFP could be addressed through a procurement process that was not subject to the OPUC Resource Procurement Rules due to the size-based exception, additional capacity deficits recently identified for 2023, 2024, and 2025 will require incremental generating capacity that exceeds the 80 MW applicability threshold for the OPUC Resource Procurement Rules. Applying the OPUC Resource Procurement

[7] IPC-E-19-14

Rules to the procurement processes needed to meet the currently identified capacity deficits in 2023, 2024, and 2025 would be extremely detrimental to the Company and its customers from both a timing and a methodology standpoint.

The proposed acquisitions, as described in this Application, are necessary and required in a dynamic energy landscape in order to continue to provide reliable and adequate electric service to Idaho Power's customers starting in the summer of 2023 and into the future. To timely meet its resource needs and continue to provide reliable service, the Company requests that it be relieved of the IPUC's requirement to follow the OPUC Resource Procurement Rules and that it be authorized to move forward with capacity resource procurements under RFP guidelines outlined below to meet the identified deficits in 2023, 2024, and 2025. As required by Idaho law, the Company would subsequently bring Certificate of Public Convenience and Necessity filings to the Commission for any supply-side resources identified through the procurement processes, with the Commission's attendant review of the resource need and expected costs for the procurement. Ultimately, a review of the prudence of costs incurred would occur in a general rate case or other revenue requirement proceeding prior to authorization of cost recovery through customer rates.

II. SEVERAL FACTORS HAVE RESULTED IN AN URGENT CAPACITY RESOURCE NEED

As noted above, Idaho Power has been generally resource-sufficient since the addition of the Langley Gulch natural gas-fired power plant almost a decade ago but has rapidly moved from an expected resource-sufficient position, through 2028, to a near-term capacity deficiency starting in 2023, since the acknowledgement of the 2019 IRP in March of this year. Idaho Power's most current L&R balance analysis as of November 2021 identifies capacity deficits beginning in 2023 and growing each year until 2026, when the B2H 500 kilovolt transmission line is expected to be operational. In addition to load growth, several factors have contributed to the notable change in the L&R balance, including significant current third-party transmission constraints limiting wholesale market import purchases at peak, the ability of DR programs to meet peak load, planning margins and methodology modernization, and environmental regulatory uncertainty and economics for fossil fuel-fired power plants and the related timing of ceasing operations at those resources.

In May 2021, the Company identified the 2023 deficit as approximately 78 MW at the time Idaho Power issued the currently pending RFP to acquire up to 80 MW of dispatchable capacity resource. The following Table 1 details the projected capacity deficits for the years 2023 through 2025, updated to include the most current data from the preparation of the 2021 IRP.[8] As shown below in Table 1, the Company's projected capacity deficits have grown to 101 MW in 2023, 186 MW in 2024, and 311 MW in 2025.

Table 1: Peak-Hour Load and Resource Balance	2023	2024	2025
	23-Jul	24-Jul	25-Jul
Surplus / Deficit (MW)	-101	-186	-311

Changes in L&R Since the 2019 IRP: Idaho Power filed its Second Amended 2019 IRP on October 2, 2020. The goal of the IRP is to ensure: (1) Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs over a 20-year planning period; (2) the selected resource portfolio balances cost, risk,

[8] As of November 30, 2021, the developer of the Jackpot Solar project indicated that a delay is likely. If Jackpot Solar is not in-service by summer 2023 then Idaho Power will need approximately 40 MW of additional summer peak capacity to meet projected customer demands.

and environmental concerns; (3) balanced treatment is given to both supply-side resources and demand-side measures; and (4) the public is involved in the planning process in a meaningful way. Historically, the Company developed portfolios to eliminate resource deficiencies identified in a 20-year L&R balance. The L&R balance from the Second Amended 2019 did not show a capacity deficiency occurring until the summer of 2028. However, the Company's L&R balance analysis has since been updated a number of times as circumstances and conditions have changed significantly in the interim, with each iteration showing capacity deficits as early as 2023.

Following development of the Second Amended 2019 IRP, the Company conducted focused system reliability and economic analyses to assess the appropriate timing of a Valmy Unit 2 exit between 2022 and 2025. The result of the reliability and economic evaluations demonstrated that coal-fired operations of Valmy Unit 2 through the end of 2025 is the most reliable and economic path forward.

The analysis that led to this conclusion started with adjustment of the L&R balance analysis used in the Second Amended 2019 IRP as part of the Valmy Unit 2 reliability and economic impact analyses completed in May 2021. Development of the 2021 IRP was occurring simultaneously, and the Company updated the L&R balance to include modifications to existing resource availability, as is standard when developing the L&R balance as part of the IRP process. First, the Company identified changes to its market purchase assumptions due to third party transmission constraints. Additionally, the existing resource availability was revised to include updated thermal capacity and reduced DR capacity determined through the refinement of the planning margin calculation. The net change between the Second Amended 2019 IRP and the updated L&R balance is a reduction of over 500 MW in available capacity each July during the 2022 through 2025 time period. As a result of these changes to the L&R balance in May

2021, the Company anticipated a capacity deficit of approximately 78 MW in 2023, assuming Valmy Unit 2 operations continue through 2025.

As can be seen on Table 1, the final L&R balance used for the 2021 IRP indicates the 2023 capacity deficit of 78 MW, as calculated in May 2021, has grown to 101 MW. While all the same factors that influenced the changes in the May 2021 L&R balance still exist, the latest L&R balance includes a revised load forecast with greater load growth projections.

Transmission Market Shifts and Constraints: In the Second Amended 2019 IRP, the Company assumed Valmy Unit 2 could be replaced with capacity purchases from the south. However, market conditions have changed dramatically because of ripple effects stemming from the August 2020 energy emergency event in California. During this event, the West experienced a heat wave, increasing the demand for energy and causing several balancing authorities across the Western Interconnection to declare energy emergencies. Generation was not able to meet demand in California and transmission capacity was strained, limiting the ability to import energy. As a result, the California Independent System Operator was required to shed firm load to maintain the reliability and security of the bulk power system. Ultimately, this also impacted Idaho Power's ability to use third party transmission to import energy and meet load deficits.

Understanding the importance of transmission availability during times of high electricity demand, third-party marketing firms began reserving unprecedented amounts of firm transmission capacity just outside the Company's border, significantly limiting Idaho Power's access to market hubs. Soon after the event, Idaho Power's own transmission service queue was flooded with multi-year requests totaling 1,293 MW, as of April 2021, looking to move energy from the Mid-C hub across Idaho Power's transmission system to the south.

While the Company is able to reserve its own transmission for usage by the Company's customers, the transmission service requests just outside of Idaho Power's borders have added constraints to an already constrained market limiting the Company's access to capacity at Mid-C. Idaho Power tested the market availability with an RFP issued April 26, 2021, which ultimately validated the existence of these transmission system constraints. The RFP requested a market purchase with delivery at Idaho Power's border; however, no bids were received at any price-point, further emphasizing the difficulty of importing energy under a constrained transmission system.

As a result of these recent and significant market changes, for the years 2023 through 2025, Idaho Power has reduced the transmission availability within the L&R balance from approximately 900 MW in the 2019 IRP to approximately 700 MW in the 2021 IRP during the peak load month of July.

Planning Margin Adjustments: The Company's planning margin is intended to provide a sufficient reliability margin to prevent the need to curtail customer demand more than one time in 20 years. The planning margin is intended to cover (1) Idaho Power's contingency reserve obligation, (2) severe weather events, consisting of both extreme heat and extreme cold, (3) poor water conditions, and (4) planned and unplanned resource and transmission outages. In the Second Amended 2019 IRP, Idaho Power established a 15 percent planning margin, which was calculated as 15 percent of the Company's average (50th percentile) peak demand forecast for each month. For example, if Idaho Power had a peak-hour-load of 3,500 MW, the Company would add the planning margin and target 4,025 MW of resource capacity (3,500 multiplied by 1.15).

Following the development of the Second Amended 2019 IRP, the Company looked to refine its planning margin in accordance with best practices to ensure consideration of issues specific to Idaho Power's system. The 15 percent planning margin utilized in the Second Amended 2019 IRP is essentially a rule of thumb. Individual utilities can experience different frequencies of demand extremes, varying forced outage rates among resources, and resource size compared to load size, all of which should be considered when determining the planning margin. Rather than continue to utilize a planning margin based on a rule of thumb, the Company modernized its approach and is using probabilistic methods in the 2021 IRP to determine system needs to ensure reliability for all hours of the day on the Company's system, which is the "LOLE method."

The LOLE approach allows for a comparison of load to generation on an hourly basis over a specified period. Given feedback from the IRP Advisory Council, and the increased frequency of extreme events, the Company aligned with the Northwest Power and Conservation Council standard of no more than one loss of load event per 20 years, or an LOLE of 0.05 days per year. The Company believes the LOLE method's hourly approach fully considers the reliability value of renewable resources over time compared to the previous method.

In addition to taking a more granular hourly approach, the LOLE method evaluates the capability of existing resources to meet peak demand through the determination of the ELCC. Use of the ELCC resulted in a change to the peak-serving capability of Idaho Power's existing resources, most notably the peak capacity contribution of DR. When analyzing the Company's system on an hour-by-hour basis, the results indicate the ability of DR programs to meet peak load under the changing dynamics of Idaho Power's system is significantly lower than previously assumed. This is primarily the result of increased solar resources on the Company's system pushing net peak load hours outside the current DR program window. Therefore, the Company has filed a request for modifications to its DR programs that, while making the programs more effective at meeting system needs, may result in lower DR participation.

Current Load Forecast Increases: While the change in peak load expectations for 2023 through 2025 between the Second Amended 2019 IRP and the May 2021 L&R analysis was relatively immaterial, based on updates the Company currently expects 2023 through 2025 peak load to be greater than anticipated in those prior analyses. Migration into the Company's service area exceeded prior forecasts, both during and after the recession, as customer additions into the service area were approximately 30% higher than prior expectations. In addition, there have been several industrial customers, both existing and new, that have made a sufficient and significant binding investment and/or interest indicating a commitment of locating or expanding operations in the Company's service area. These drivers predict that the Company's peak capacity by 2023 will grow faster than forecasted expectations used in both the second amended 2019 IRP and the May 2021 L&R analysis.

Current L&R Balance Analysis: Since the Valmy study was completed in June 2021, the Company has continued to update the L&R balance analysis for the 2021 IRP using the most currently available resource and load inputs. On the resource side, Idaho Power has applied the adjusted transmission assumptions, as well as the LOLE and ELCC methods described above. On the load side, Idaho Power has also included higher load growth expectations. The resulting capacity deficiency of approximately 101 MW in 2023, 186 MW in 2024, and 311 MW in 2025 as presented in Table 1, clearly demonstrates the need for the new capacity resource to meet those capacity deficits prior to the addition of the Boardman to Hemingway transmission line in 2026.

While these estimates reflect Idaho Power's best available information at the time of this filing, the Company wishes to make the Commission aware of a recent development that could ultimately increase the forecast capacity deficit beginning in 2023. Idaho Power had previously contracted with Jackpot Solar, LLC ("Jackpot Solar") for 120

MW of solar generation to become commercially operational by December 2022. The energy contract with Jackpot Solar was reviewed and approved by the Commission by Order No. 34515 issued in December 2019.[9] On November 9, 2021, Jackpot Solar informed Idaho Power that that global supply chain disruptions have raised concerns regarding Jackpot Solar's ability to achieve commercial opperation by the dates identified in the approved agreement. Specifically, Jackpot Solar alleges that current global supply chain disruptions brought on by the COVID 19 pandemic represents a force majeure event as defined in the energy sales agreement, as its solar modual supplier will not meet the supply provisions of the modual supply agreement. Idaho Power is currently in discussions with Jackpot Solar, and it is unknown to the Company when, or if, the associated 120 MW of solar generation will begin commercial operations. If the Jackpot Solar project is delayed beyond summer 2023, or not built, Idaho Power will need approximately 40 MW of incremental peak capacity to meet projected customer demands.

III. THE OREGON RESOURCE PROCUREMENT RULES ARE UNABLE TO TIMELY ADDRESS DYNAMIC CIRCUMSTANCES

On February 9, 2010, the Commission initiated Case No. IPC-E-10-03 to establish competitive bidding guidelines for the RFP process used when supply-side resources are acquired by Idaho Power. On February 12, 2013, the Commission issued Order No. 32745 closing the case without establishing Idaho-specific resource procurement guidelines, but rather directed Idaho Power to comply with RFP guidelines applicable in its Oregon service area. According to Order No. 32745, the Company is required to adhere the Oregon Competitive Bidding Guidelines should it commence an RFP process for a new supply-side resource prior to the development of Idaho-specific RFP guidelines. The referred to Oregon RFP Guidelines were later codified into the administrative rules

[9] Case No. IPC-E-19-14.

of the OPUC. OAR 860-089-0010 *et. seq.*. The OPUC Resource Procurement Rules impose Competitive Bidding Requirements upon an electric utility for the "acquisition of a resource or a contract for more than an aggregate of 80 megawatts and five years in length," among other requirements. OAR 860-089-0100(1)(a). There are certain exceptions to the applicability of the OPUC Resource Procurement Rules, including the one used for the Jackpot Solar contract: "There is a time-limited opportunity to acquire a resource of unique value to the electric company's customers." OAR 860-089-0100(3)(b). The OPUC Resource Procurement Rules also contain an exception to their applicability based upon the OPUC acknowledging an alternative acquisition method in the utility's IRP. OAR 860-089-0100(3)(c).

Idaho Power asks that the Commission relieve Idaho Power of the IPUC's requirement to follow the OPUC Resource Procurement Rules in the state of Idaho. A procurement process that complies with all requirements set forth by the OPUC Resource Procurement Rules would not timely address the Company's near-term resource needs and would be unnecessarily costly. By Idaho Power's estimates based upon the required timelines from the OPUC Resource Procurement Rules, it could take a minimum of more than 18 months from the initial stages of selection of the required independent evaluator until the final step of the process where the OPUC approves the short list of bidders. *See*, Attachment 1 hereto, incorporated herein by this reference. In fact, PacifiCorp's 2017 wind resource RFP took nearly a year from PacifiCorp's first filing to the OPUC's decision on the short list of bidders. *See In the Matter of PacifiCorp, dba PacifiCorp Power,2017R Request for Proposals*, OPUC Docket No. UM 1845, Order No. 18-178 (May 23, 2018). And even though it took nearly a year just to identify the short list of bidders, the RFP process was considered "expedited" and the OPUC referred to it as "fast-moving." *Id.* at 8, 10.

PacifiCorp's 2020 all-source RFP has taken even longer. PacifiCorp initiated the RFP with an OPUC filing in February 2020 and now—over 20 months later—the OPUC has yet to rule on the short list of bidders. *See In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of 2020 All-Source Request for Proposals*, OPUC Docket No. UM 2059. This timeframe does not take into account the time to actually engineer and construct the generation resources, which can take up to another two years to complete.

PacifiCorp also recently submitted its initial OPUC filing for its 2022 all source RFP. *See In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of 2022 All-Source Request for Proposals*, OPUC Docket No. UM 2159. PacifiCorp's initially proposed schedule called for submission of its final shortlist by May 2022, eight months after the initial filing. OPUC Staff referred to the proposed schedule as "aggressive" and claimed that the schedule did not comply with the OPUC's rules. *See In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of 2022 All-Source Request for Proposals*, OPUC Docket No. UM 2159, Order No. 21-351, App'x A at 5 (Oct. 25, 2021). In response, PacifiCorp modified the schedule to include 80 more days on the front end before the RFP may be approved by the OPUC and over 200 more days for bidders to prepare their bids. Under the now extended schedule, PacifiCorp will not even issue the RFP until April 1, 2022—seven months after the initial filing—and the RFP process will not conclude until May 2023—more than 19 months after PacifiCorp's initial OPUC filing.

Portland General Electric Company (PGE) also recently initiated the OPUC RFP process with a filing in April 2021. *In the Matter of Portland General Electric Company Application for Approval of Independent Evaluator for 2021 All Source RFP*, OPUC Docket No. UM 2166. Under the approved schedule, PGE anticipates issuing the RFP in December 2021—more than seven months after initiating the OPUC process—and PGE anticipates submitting its final shortlist in June 2022—more than a year after initiating the OPUC process. *In the Matter of Portland General Electric Company Application for Approval of Independent Evaluator for 2021 All Source RFP*, OPUC Docket No. UM 2166, Schedule for Post IE Selection (August 3, 2021).

An RFP process that takes over 12-18 months, in addition to the time to go from an approved RFP shortlist through negotiations, engineering, and construction, is clearly not practical in the current dynamic, rapidly changing environment, as evidenced by the changes in the transmission market conditions, customer growth, and corresponding resource needs between the 2019 and 2021 IRPs. The resource needs of the Company and its customers emerge with such urgency, such as the present capacity deficits identified in 2023, 2024, and 2025, that the Oregon Resource Procurement Rules and process is not viable if the Company is to reliably serve customers. Concurrent with this Application, Idaho Power will file a request with the OPUC to waive the applicability of the OPUC Resource Procurement Rules to Idaho Power in its Oregon jurisdiction for the required resource acquisitions discussed herein for 2023, 2024, and 2025.

Idaho Power is also concerned that the OPUC Resource Procurement Rules do not align with the state of Idaho's system of public utility regulation. In fact, Idaho Power objected to the adoption of the Competitive Bidding Guidelines, the precursor to the OPUC Resource Procurement Rules. Under the state of Idaho's chosen system of public utility regulation, customers benefit in the long-term when the utility is responsible for the obligation to reliably serve customers within its certificated service area, subject to IPUC oversight over, among other things, capacity resource acquisition. Additionally, Idaho Power believes the OPUC Resource Procurement Rules are very inflexible, unrealistic as to timing, and introduce a bias against the acquisition of utility-owned resources into generation resource procurements, favoring the standalone per-MWh price of a fixed term contract (typically well short of the useful life of the asset) over reliability, long-term customer impacts, and the financial viability of the utility. The OPUC Resource Procurement Rules are designed to favor least cost PPA resources that are not the optimal resources operationally or for a utility such as Idaho Power that already holds a proportionately large amount of PPAs. By contrast, a procurement process for resources that takes into account not only price, but also reliability, system operation, long-term operation and maintenance of facilities, financial viability of the utility, economic dispatch, environmental policies, real-time needs and load growth, and other attributes, is one that benefits customers, developers, and the utility.

IV. IDAHO POWER'S RFP PROCESS, AND THE MANDATORY CPCN, CREATE AN IDEAL PROCESS AND PROTECTIONS

Idaho Power seeks authority to proceed with supply-side resource procurements designed to meet the identified capacity deficits in 2023, 2024, and 2025 - prior to the time that the B2H transmission line is expected to be operational - in much the same manner that all prior supply-side resources have been procured and approved by the IPUC for Idaho Power. For all of those resource acquisitions, the Company will conduct an RFP to obtain competitive pricing and identify the best resource to ensure adequate, reliable, and fair-priced service to its customers, and will then bring that resource to the IPUC for its independent evaluation and determination as to whether acquisition of that resource is consistent with the Public Convenience and Necessity under applicable standards. *Idaho Code* § 61-526.[10]

As previously stated, Idaho Power has initiated an RFP for a dispatchable capacity resource up to 80 MW in order to meet the initially identified 78 MW capacity deficit in

[10] Notably, the state of Oregon does not have a corresponding requirement for the issuance of a CPCN for supply-side or generation resources like Idaho.

2023.[11] In the Spring of 2021, recognizing the urgency of the capacity deficit, the Company assembled an interdisciplinary team to develop and process an RFP for 2023 peak capacity resources ("RFP evaluation team"). The Company also retained a consultant, Black & Veatch Management Consulting, LLC, to assist the RFP evaluation team with development of the RFP and to provide guidance and evaluation support of the Company's RFP process. The RFP evaluation team developed detailed criteria and a methodology for evaluating both price and qualitative attributes of a proposed resource. On June 30, 2021, the RFP evaluation team issued a formal request for competitive proposals for up to 80 MW of electric generating capacity. The RFP document is attached hereto as Attachment 2 and incorporated herein by this reference. The RFP document sets forth the process and procedure utilized to solicit and evaluate the proposals as to meeting the Company's and its customers' present needs.

A public Notice of Intent was released on May 20, 2021, to industry developers and media outlets and was posted to Idaho Power's website noticing Idaho Power's intent to release the RFP. Interested developers responded with an Intent to Bid by June 11, 2021. The "2021 All Source Request for Proposals for Peak Capacity Resources" was solicited directly to 38 Developers. The RFP solicitation identified the purpose, key product specifications, proposal format, qualitative and quantitative evaluation criteria, template draft form term sheet ("Build Transfer Agreement" or "BTA"), technical specifications, and additional requirements necessary to submit a qualifying proposal. The RFP solicitation also focused on the importance of having a project in-service by June 2023. Thirteen proposals were submitted by third-party developers on August 11, 2021. The RFP evaluation process assesses both price and non-price attributes. Price

[11] The Oregon Procurement Rules do not apply to resources below 80 MW.

attributes were weighted at 60 percent of the total valuation and non-price attributes were given a 40 percent weighting.

Once a winning bidder is selected and contractual documents are executed, the Company, as it has done in the past, will bring the proposed generation acquisition to the Commission for is review in a CPCN proceeding to establish both the need and expected cost of the procurement. The required CPCN process as well as the subsequent rate making proceedings will provide considerable oversight of the procurement process, and ensure low cost, reliable resource acquisitions for customers - as it has done for the Company's more than 100-year history.

V. UTILITY OWNERSHIP OF SUPPLY-SIDE CAPACITY RESOURES IS BENEFICIAL TO CUSTOMERS, THE UTILITY, AND IDAHO'S REGULATED UTIILITY MODEL

Idaho's Regulatory Mandate and Model: Idaho Power has an obligation to provide adequate, efficient, just, and reasonable service on a nondiscriminatory basis to all those that request it within its certificated service area. *Idaho Code* §§ 61-302, 61-315, 61-507. As part of the regulatory compact, Idaho Power must serve all customers in the service aera, in exchange for its exclusive right to provide retail electric service within the service area. The compact provides Idaho Power the opportunity to earn a reasonable return by investing capital into the resources and systems necessary to perform its service obligation. At the same time, the Commission has oversight of the provision of that service and must assure that the rates Idaho Power charges its customers and that the rules and regulations by which it provides service are just, reasonable, nondiscriminatory, and non-preferential. *Idaho Code* §§ 61-501, 61-502, 61-503, 61-507, 61-508.

The Company must at times acquire additional resources to meet the identified capacity deficits on its system, regardless of when those deficits occur and with whatever urgency they arise, in order to comply with its continuing obligation to serve customers. While the IRP provides insight into resource procurement, it is a biennial process, and circumstances change in the interim that can make resource procurement for reliable load-service more urgent, as is the present case. Additionally, those resource acquisitions must take into account the benefits of utility ownership and operation of resources, and not be premised solely on short-term/least-cost, which can have catastrophic outcomes for electric service and the public. The Commission has oversight of those procurements, to ensure the company is prudently investing its capital. With only limited exception, these resources should be Company-owned, as Idaho Power must satisfy its obligation to provide its customers with reliable service and at the same time maintain its financial health to remain a viable, going-concern, regulated entity in the state of Idaho's chosen and mandated system of regulated public utility service.

The Commission has the express authority to order a utility to build new structures, or to upgrade and/or improve existing plant and structures, in order to secure adequate service or facilities. Idaho's applicable statute states:

> Whenever the commission, after a hearing had upon its own motion or upon complaint, shall find that additions, extensions, repairs or improvements to or changes in the existing plant, scales, equipment, apparatus, facilities or other physical property of any public utility . . . ought reasonably to be made, or that a new structure or structures should be erected, to promote the security or convenience of its employees or the public, or in any other way to secure adequate service or facilities, the commission shall make and serve an order directing such additions, extensions, repairs, improvements, or changes be made or such structure or structures be erected in the manner and within the time specified in said order.

Idaho Code § 61-508.

A Certificate of Public Convenience and Necessity represents the exercise by the Commission of foundational authority and principles that are necessary in Idaho's system of permitting regulated, vertically integrated public utilities to exist and to provide necessary services to the public. Certificates have been utilized in various ways from the time that Idaho's statutory system of public utility regulation was enacted by the Legislature in 1913, *Idaho Code* § 61-101, *et seq*., to the present time. After over 100 years of legislative enactments, Commission orders, and Idaho Supreme Court reviews, the Certificate remains the embodiment of the Commission's fundamental power and authority to, at the most basic level, authorize and direct a public utility to serve in the public interest. *See Idaho Power & Light Co. v. Bloomquist et al.*, 26 Idaho 222, 141 P.1083 (1914); *Idaho Op. Atty. Gen. No. 87-2*, 1987 WL 247587 (Idaho A.G.).

In the broadest sense, a Certificate allows a company that meets the definition of a "public utility" pursuant to *Idaho Code* § 61-129 to exclusively provide its service to the public in a specified geographic region, its service area. It is a codified part of the "regulatory compact" whereby the utility takes on the exclusive obligation/right to serve all those requesting service within its service area and, correspondingly, submits itself to the rate and service quality regulation of the Commission. In a more literal sense, a Certificate from the Commission is required for the construction or extension of a line, plant, or system by any street railroad, gas, electrical, telephone, or water corporation. *Idaho Code* § 61-526. § 61-526 also provides that "if public convenience and necessity does not require or will require such construction or extension [of a line, plant, or system] the commission . . . may, after hearing, make such order and prescribe such terms and conditions for the locating or type of line, plant or system affected as to it may seem just and reasonable . . . ." A CPCN is required for the utility to construct a new generation resource or plant but is not required to increase the capacity of existing generating facilities. *Id*. The required CPCN provides a broad mechanism for considerable regulatory oversight into the procurement process for a generation or supply-side resource - one that is fundamental to our system of regulation and has historically in Idaho been exercised for the benefit of both the utility customers and the utility.

Idaho's system of regulation is based upon the core concept that state regulation of a single service provider in the public interest is better than, and preferrable to, an environment of competition and competitive service providers. *See Idaho Power & Light Co. v. Bloomquist et al.*, 26 Idaho 222, 141 P.1083 (1914) ("*Bloomquist*"). The positive virtues of this system of regulation have been repeatedly confirmed. Idaho's public utility laws were enacted in 1913. A seminal case, *Bloomquist,* in 1914 considered the constitutionality of the state's public utility laws and held that they were consistent with both the state and federal constitutions. *Bloomquist*, 26 Idaho 222, 141 P. at 1097. In its decision upholding the enactment of the public utility laws in the state of Idaho as constitutional, the Idaho Supreme Court stated,

> There is nothing in the Constitution that prohibits the Legislature from enacting laws prohibiting competition between public utility corporations, and the Legislature of this state no doubt concluded that a business like that of transmitting electricity through the streets of the city and furnishing light and power to the people must be transacted by a regulated monopoly, and that free competition between as many companies or as many persons as might desire to put up wires in the streets is impracticable and not for the best interests of the people.

Bloomquist, 26 Idaho 222, 141 P. at 1088. The Court analyzes and discusses the regulation of a single service provider, as a monopoly, by a state commission as a lawful, valid, and preferred substitution for the control of public utilities by competition. The Court in its discussion refers to several quotes citing the benefits of a regulated monopoly environment over a competitive environment, stating "In our opinion, the government, which properly assumes to prescribe reasonable rates and compel adequate service by public utilities, should also protect such utilities and the public from unwise and useless competition, and the wasteful investment of capital in the unnecessary duplication of plants." *Bloomquist*, 26 Idaho 222, 141 P. at 1089 (quoting Forty-First Report of the Georgia Railroad Commission). The Court stated,

> The regulating of rates and compelling proper service is for the purpose of obtaining rates and service as nearly equitable as possible to both the consumer and the utility corporation, and competition can have no other effect than to destroy the very groundwork of regulation, and therefore competition may be regulated by a commission under laws enacted by the Legislature.

Bloomquist, 26 Idaho 22, 141 P. at 1089. In addressing Idaho's public utility laws in particular the Court stated,

> Under the act in question, the commission is given power to fix the rate absolutely, and neither of the competing companies can charge more or less than the rate fixed. Under those conditions competition can amount to nothing, and the only reason for having two corporations covering the same field is to secure satisfactory service. But, under our utilities act, the commission is the arbitrator in regard to all matter of service. If the utility corporation is not giving satisfactory service, the commission has absolute power to compel it to do so. If its facilities are such that the cost of operation is unnecessarily high, the commission can enforce the installation of proper machinery and facilities and a correspondingly proper charge for the commodity furnished. The commission may force the public utility to keep abreast of the times in the employment of proper machinery and appliances in their plants and in the economic conduct of its business. If wasteful methods are indulged in, the public utility must bear the loss, and not the consumer. Thus the reason for competition is entirely taken away.

Bloomquist, 26 Idaho 222, 141 P. at 1089.

The state of Idaho and Idaho Power's customers are better served by the traditional, rate-based, vertically integrated single service provider model, as discussed and held lawful in *Bloomquist,* than the various incarnations of competition and eroded monopolies subjected to undue competition by modern forces. By design, Idaho's chosen system of regulation is set up to protect the utility service provider from competition in its certificated service area, whilst subject to Commission oversight, and not to promote competitive forces against the utility such that the utility eventually erodes and ceases to be viable. Instead, Idaho's long-standing, successful, and lawful system of utility regulation relies upon and needs financially healthy utilities that are able to rate base investment that is used and useful in the public service and have an opportunity to earn a return on that investment at a regulated rate.

The modern tools used in attempts to force deregulation onto state jurisdictions that have chosen to retain the traditional vertically integrated, state regulated service providers, such as the Public Utility Regulatory Policies Act of 1978 ("PURPA") and its unbounded mandatory purchase Power Purchase Agreements ("PPAs"), the Federal Energy Regulatory Commission's ("FERC") promotion of Regional Transmission Organizations ("RTO") and Independent System Operator ("ISO") operational environments, anticompetitive tax credit policy for renewable energy procurement, and competitive procurement rules and regulations specifically designed to "remove the utility's competitive advantage" (or in other words to give competitive advantage to non-utility, third-party generation or PPAs with incentives mis-aligned with customer benefit). While some aspects of these policies can, and have, resulted in positive outcomes for utilities and the customers they serve, certain policy aspects, if not properly implemented, have the potential to create an environment that erodes the financial health and viability of the regulated utility, and the ability of a utility to reliably serve customers, and in turn can erode the state's ability to protect customers through its regulation of the public utility.

These tools of deregulation, promoting a proliferation of third-party, PPA generation resources creates an environment where the public utility is no longer protected from competition in its certificated service area, but must still be subjected to the economic regulation of the state and face disadvantages in the marketplace. In essence, the model gravitates toward defaulting the utility and its customers into less useful, more expensive, and operationally difficult PPA arrangements that undermine the regulatory environment while allowing non-utility, third party generators - who have no obligation to customers and mis-aligned incentives - to walk away with profits and to consider their own bottom line, as opposed to reliable service to electric utility customers.

Non-utility generation or plant such as PPA or similar arrangements may have a viable and lawful place amongst a public utility's diverse portfolio of resources as a seemingly low-cost dump of energy onto the system. However, PPAs are of very limited value to meet capacity deficits when the generation generally cannot be controlled, dispatched, curtailed, available, or economically managed for the benefit of customers and the company in the same manner as utility-owned generation. PPAs may have an initial appearance of being a lower-cost generation resource alternative, but this can be false in the context of full utility operations. If one looks beyond just the price per MW in the written contract and looks at how useful the PPAs generation is to the system and the entirety of the financial costs to customers in the long run, their appeal diminishes rapidly in many contexts. As the amount of PPA generation resources in a public utility's portfolio increases, a number of issues arise: integration of the power becomes more difficult and costly; the utility loses maintenance and control over the facility and its condition; the utility typically loses the generation resource at a specified contract date short of the useful life of the plant; the utility is relegated to the terms of the contract; curtailment of the facility is non-existent, expensive, or fraught with potential legal challenges; and cyber and physical security oversight of the facility is diminished. Further, it starts to undermine the regulated service provider model, and acts in effect as a tool for deregulation.

During the early 1990's, many states, including Idaho, considered the enactment of legislation to deregulate the electric utility industry. Deregulation was considered and rejected in Idaho primarily based upon the success of the vertically integrated, state-regulated service provider system of regulation, the corresponding regulatory compact, and the state commission-based system of regulation that has resulted in Idaho electric customers consistently enjoying some of the lowest cost and most reliable electric service in the nation. This is bolstered by the additional security and customer protection afforded by the regulator maintaining oversight of the utility, as opposed to the unregulated, third-party who is not concerned with, nor answers to, customers or the regulator and is only concerned with profits.

In fact, many jurisdictions that went down the road of enacting deregulation legislation, particularly in the east, employed initial price caps to protect customers from inflated electric rates as part of the package. However, as time would tell, once those initial price caps expired those jurisdictions experienced very large price increases to customers, in many cases far exceeding those in regulated jurisdictions and with no recourse to the regulators. More recently, it was reported that since 2004 deregulated Texas electricity residential customers paid $28 billion more for their power than they would have paid at the rates charged to the customers of the state's traditional utilities.[12] From 2004 through 2019 that the annual rate for electricity from Texas's traditional utilities was 8 percent ***lower***, on average, than the nationwide average rate, while at the same time the rates of de-regulated retail providers averaged 13 percent ***higher*** than the nationwide rate.[13]

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[12] *Texas Electric Bills Were $28 Billion Higher Under Deregulation*, Tim McGinty and Scott Patterson, Wall Street Journal, Feb. 24, 2021.
[13] *Id*.

The Texas Model is a Cautionary Tale: Recent system reliability events in Texas offer a cautionary tale regarding the risks associated with a restructured electric generation sector.[14] In 1996, the Electric Reliability Council of Texas ("ERCOT") was established as the Independent System Operator ("ISO") in the state of Texas (approximately 10% of Texas is not served by ERCOT), as provided for in Senate Bill 373. Subsequently in 2002, vertically integrated electric utilities were required to restructure by separating their generation, transmission, and distribution functions into separate entities. One of the goals of this restructuring was to create competition in the wholesale electric energy market. While restructuring has certainly accomplished that goal, it has also changed the financial and regulatory model that drives investment in generation resources in the state. Under the vertically integrated utility model that existed in Texas prior to 2002, investor -owned utilities had a financial incentive to invest in and maintain generation resources to meet their obligation to provide safe and reliable service to customers. In exchange for that obligation to serve, investor-owned utilities were provided an opportunity to earn a reasonable financial return for shareowners. Ultimately, the state regulator, the Public Utility Commission of Texas ("PUCT"), determined the prudence of those investments. Under a restructured market, independent generation operators do not have the same regulatory oversight or financial incentives, which may have led to underinvestment in the Texas generation fleet, and thereby compromising system reliability.

In February 2021, much of the ERCOT system was being impacted by extreme cold weather associated with Winter Storm Uri, which resulted in prolonged power

[14] Source information for this section: *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts A report by a committee of faculty and staff at The University of Texas at Austin July 2021*, attached hereto as Attachment 3, and incorporated herein by this reference.

outages during the week of February 14. More than 4.5 million homes and business lost power during this event, and at least 210 people died as a direct result of those outages. The outages occurred despite ERCOT's best efforts in the days prior to deploy operating reserves, load shedding, and other conservation measures.

By February 15, 2021, ERCOT experienced generation outages of over 50,000 MW, or approximately 40 percent of total ERCOT nameplate generating capacity. Of those outages, approximately 30,000 MW, representing 167 generating units, experienced weather-related outages. These weather-related issues included, but were not limited to, wind turbine icing, frozen water intakes, and freezing of other general equipment.

The financial fallout from this event was also severe. The financial pain caused by these events impacted all categories of market participants, including wholesale energy suppliers, retail energy suppliers, and retail customers. Wholesale energy prices reached $9,000/MWh. Extremely high prices led to unpaid power payments within ERCOT of nearly $3 billion by May 2021. Retail providers experienced negative financial impacts in the billions of dollars, with several bankruptcies occurring in the aftermath.

It is important to note, all of the operational and financial chaos brought on by this extreme weather event occurred with relatively little transparency or oversight by the PUCT, even though Texas law requires the PUCT to analyze and report on the preparedness of generating units to operate during extreme weather events. The last such report was filed with the legislature in 2012. The reduced regulatory oversight and changed business model that exists in Texas is a clear reminder of the risks that exist in deregulated electric markets. Deregulated power generators serving ERCOT did not have the incentive to invest in systems to address extreme weather events, as presumably they were single-mindedly focused on maximizing profits instead of providing reliable service to customers in Texas. These tragic events demonstrate the that "invisible hand" of the free market doesn't work well in extreme situations because the economic signals don't last long enough to incent the investments that are necessary to ensure reliability during those events.

Third Party-Owned Assets Have an Imputed Debt Cost to the Utility and Ultimately to Customers: A PPA brings added costs beyond the direct contract costs for the purchased energy in the form of imputed debt adjustments made by credit rating agencies. When Idaho Power enters into a PPA for third-party supply of energy, credit ratings agencies like Standard and Poor's (S&P), Fitch, and Moody's view such agreements as creating fixed debt-like obligations given the lengthy stream of payment obligations by the utility. In light of this view, credit agencies make what are called "imputed debt adjustments" to Idaho Power's credit metrics to reflect the credit exposure that exists with PPAs. Ultimately, these imputed debt adjustments amount to real costs that are passed on to Idaho Power's customers through the rate-making process over time, but not visible in the PPA.[15]

Imputed debt adjustment calculations can vary depending upon the level of perceived credit exposure associated with a PPA, typically as apportioned between Idaho Power and its customers based on the certainty of rate recovery provided for by applicable law or regulatory assurances. The adjustment process begins with a calculation of the net present value ("NPV") of the outstanding contract payments over the remaining life of a PPA. The NPV value is then adjusted for the level of perceived credit exposure associated with a PPA. Depending on the perceived credit exposure of a PPA, the credit

[15] Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements Primary Credit Analyst: David Bodek, Secondary Credit Analysts: Richard W Cortright, Jr. and Solomon B Samson, May 7, 2007, attached hereto as Attachment 4 and incorporated herein by this reference.

rating agency may apply risk factors that typically range from 0 to 50 percent – but can be as high as 100 percent.[16]

Ultimately, the result of the imputed debt applied by the rating agencies will be downgrades in credit ratings unless there is some type of mitigation to offset the imputed debt, such as additional equity. For example, in June 2021 Moody's put Idaho Power on negative watch, which is the first step towards a down grade in Moody's credit ratings for the company. There are many factors that impact credit ratings, and the imputed debt is one of those factors.

In comparing the cost of a PPA to utility ownership it is important to consider these imputed debt adjustments and their resulting cost. To illustrate the financial impact of the imputed debt adjustment, the Company has prepared the following illustrative example using the following financial input assumptions:

- Current authorized return on equity = 10%
- Incremental Cost of debt = 4%
- Incremental composite tax rate 25.74%

Any PPA will cause rating agencies to impute debt on Idaho Power's balance sheet based on the estimated present value of the PPA resource payments discounted at the incremental cost of debt and adjusted by a risk factor. In order to maintain an assumed 50/50 capitalization structure, the imputed debt will require an equal amount of equity to be issued to maintain the current debt equity ratio.

Assume the Company signs a PPA that would result in imputed debt of $100 million on the Company's balance sheet based on the estimated payments and the incremental debt rate and risk factor. In order to maintain a 50/50 debt/equity ratio, the company must

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[16] *Id*.

issue $100 million of equity. The company would use the $100 million proceeds of the equity issuance for ongoing capital projects.

As a result, Idaho Power customers would now pay the monthly/annual cost of the PPA plus the cost of the equity issuance due to the PPA ($100 million*10%) = $10 million plus a gross up for tax ($10 million* (1/(1-0.2574))) = $13.466 million.

As mentioned earlier, the Company would use the funds from the equity issuance to cover the cost for the on-going capital projects needed to reliably serve Idaho Power customers. However, had the Company financed those same capital projects with a blend of 50% debt and 50% equity, the cost to customers would be $100 million * (4%*50%+10%*50%) = $7 million plus a gross up for tax ($7 million *(1/(1-0.2574))) = $9.426 million.

Therefore, in this example, customers would be paying an additional $4.04 million ($13.4662M - $9.426M) per year beyond the PPA price due to the imputed debt adjustment. Consequently, because of imputed debt, when evaluating the relative cost of a PPA, regulatory bodies should consider the less-visible added annual customer cost of $40.4 for every $1,000 of imputed debt related to the PPA.

PPAs May Bring Other Hidden Harms to Customers: Most PPAs are much shorter in duration than the physical and economic life of the underlying asset and generally start with a low and attractive cost in the first year but increase every year thereafter. At the end of the PPA Idaho Power must procure a new resource to cover the expiring PPA or renew the PPA at the then current market prices, which may be much higher. The owner of the PPA has the physical asset that hedges the likely increases in market prices and then passes along to customers the higher market-based costs. When Idaho Power owns an asset, customers benefit from locking in the fixed costs over the full life of the underlying asset, and as market prices go up, customers pay less on a nonlevelized basis than they did the first year the resources was in service due to depreciation. Customers also benefit by the assurance that Idaho Power will diligently maintain the asset, potentially extending the use on behalf of customers beyond the expected physical life.

Idaho Power recently performed an analysis using information from our current RFP for an 80 MW resource which compared the lowest PPA cost for solar from the bidders including the renewing of the PPA to match the life of the asset of 35 years as well as adding the impact of imputed debt compared to an ownership option, the company could save customers over $175 million over the 35-year life of the asset and over $30 million customer savings on a net present value basis. See Attachment 5 hereto, incorporated herein by this reference.

Risk of the PPA Failing to Produce or the Resource Not Being Built: Another cost to customers is when a contracted PPA does not actually show up due to circumstances that the Company cannot control, as appears to be the case with Jackpot Solar and its PPA for 120 MW of solar scheduled to be online by December 2022 prior to the currently identified capacity deficits. When the Company relies on a PPA and includes it in its IRPs for a number of years, the cost to replace such a resource without the advantage of the time that the developer had to build-out the resource, can be much more costly and it can create significant operational risks and constraints.

Idaho Power's Request Benefits the Utility and Customers: Once again, we are at a crossroads where the regulatory compact is being challenged , only this time it is not in the form of proposed legislation - it is in the form of non-utility ownership of generation assets, promoted by mechanisms such as PURPA, disproportionate tax incentives and practices, and state-mandated resource procurement rules designed to advantage non-utility generation that act to erode the financial viability of vertically integrated utilities. Ultimately this impacts customers through higher long-term costs and the potential erosion of system reliability. As the Company rapidly transitions from being resource sufficient to the identified capacity deficits in 2023, 2024, and 2025, Idaho Power asks the Commission to recognize and uphold the long-standing and successful regulatory policy of this state as originally set forth in *Bloomquist*, acknowledging the required protection of both the utility and customers from the destructive forces of this emerging form of deregulation , and setting forth regulatory policy acknowledging the customer benefits of utility ownership of supply-side capacity resources under the regulated utility business model.

VI. COMMUNICATIONS AND SERVICE OF PLEADINGS

Communications and service of pleadings with reference to this Application should be sent to the following:

Donovan E. Walker
Lead Counsel
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
Boise, Idaho 83707
dwalker@idahopower.com
dockets@idahopower.com

Tim Tatum
Vice President, Regulatory Affairs
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
Boise, Idaho 83707
ttatum@idahopower.com

VII. CONCLUSION

Idaho Power has been in a resource sufficient position for almost a decade since the addition of the Langley Gulch combined-cycle, natural gas-fired power plant, in 2012. Over the course of approximately two months - from the March 2021 acknowledgement of the 2019 IRP to the revised Load and Resource Balance in May of 2021 - Idaho Power rapidly identified near term capacity deficiencies starting in summer 2023 and growing through 2024 and 2025 until the B2H 500 kilovolt transmission line is expected to be operational in 2026. These rapidly emerging capacity deficits are driven by an increasing population and associated emergent demands in the Company's service area; third-party transmission constraints; changes to the assumptions in the L&R balance regarding available transmission capacity following the retirement of coal plants; the unavailability of import transmission capacity on the market; planning margin adjustments associated with incorporating LOLE and ELCC planning methodologies; and the potential diminishing demand response resource and solar effectiveness during peak and critical times.

Idaho Power must meet its obligation to reliably serve customers and must meet those capacity deficits to prevent wide-spread outages in its service area. The Company must do this in a rapidly changing and dynamic environment, with an already short turn-around time to meet deficits in 2023 exacerbated by an environment of global supply chain disruption and issues preventing the timely construction of new resources as well as previously contracted PPA generation from coming online in a timely manner.

Idaho has a long, successful history of state commission regulation of public utility service providers, focused on the public interest and Commission oversight. The Commission's regulation, particularly through the required CPCN and rate-making processes, provides sufficient protection and has benefit for both customers and the Company, and has served Idaho customers and Idaho Power very well for over 100 years. For the reasons cited above in this Application, Idaho Power asks the Commission for authority to move forward expeditiously with the procurement of capacity resources needed to provide adequate, reliable, and fair-priced service to customers to meet the identified capacity deficits in 2023, 2024, and 2025.

VIII. REQUEST FOR RELIEF

Idaho Power respectfully requests that the Commission issue an order authorizing the Company to move forward with the procurement of dispatchable resources needed to secure adequate, reliable, and fair-priced service to customers. More specifically, Idaho Power requests that the Commission issue an order: (1) eliminating the IPUC requirement to comply with OPUC Resource Procurement Rules; (2) authorizing Idaho Power to move forward expeditiously with resource procurements to meet identified generation resource needs in 2023, 2024, and 2025; and (3) affirming support and the continuation of the state of Idaho's system of public utility regulation under which the interests of customers are best served by a vertically integrated electric utility maintaining ownership of the necessary generation, transmission and distribution utility functions, with limited exceptions.

Idaho Power requests that the Commission issue Notice of this Application, set an intervention deadline, and convene a prehearing conference in this matter at its earliest convenience to establish a proper procedure to expedite the orderly conduct and disposition of this proceeding. RP 211.

DATED at Boise, Idaho this 3rd day of December 2021.

Donovan E. Walker

DONOVAN E. WALKER
Attorney for Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

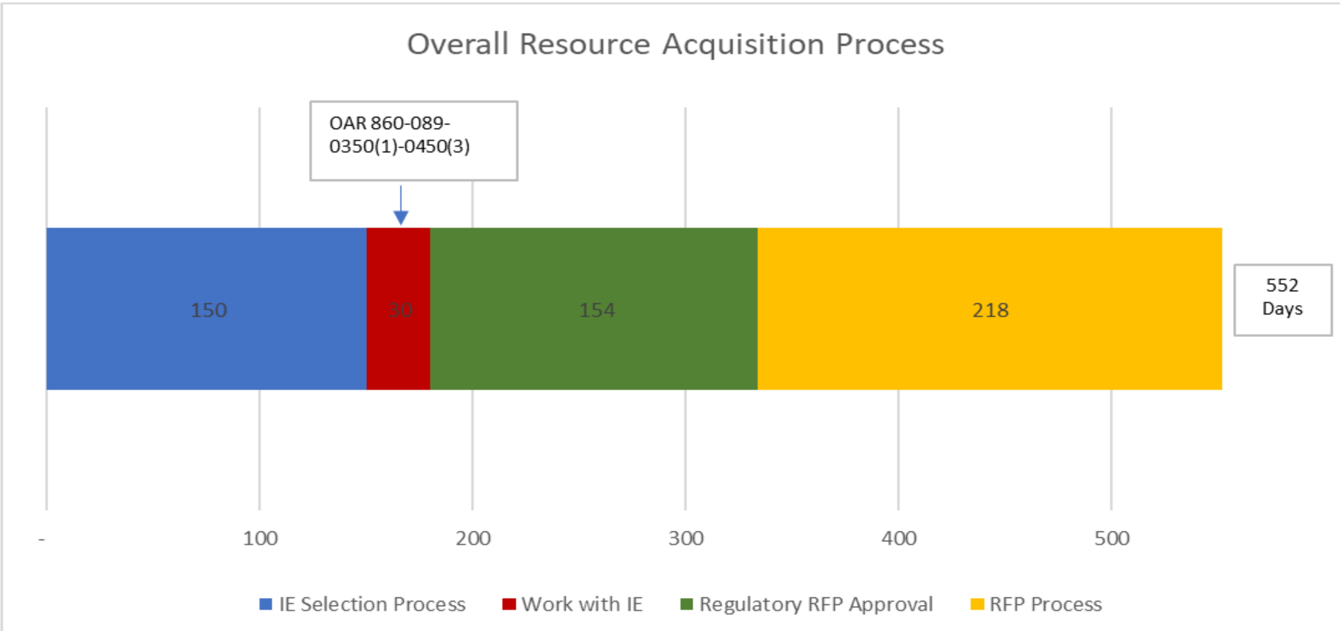
CASE NO. IPC-E-21-41

IDAHO POWER COMPANY

ATTACHMENT 1

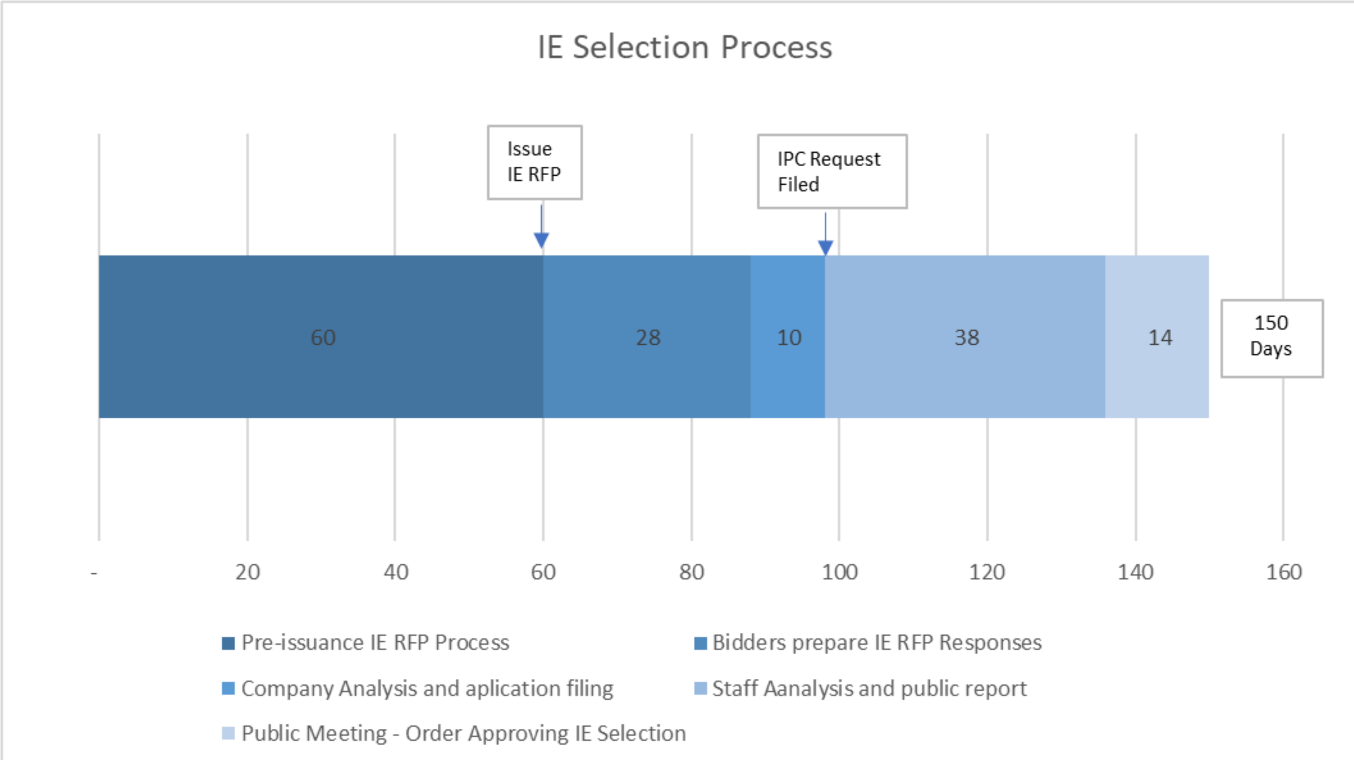
<u>Timeline for Oregon Competitive Bidding Rules</u>

https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4519



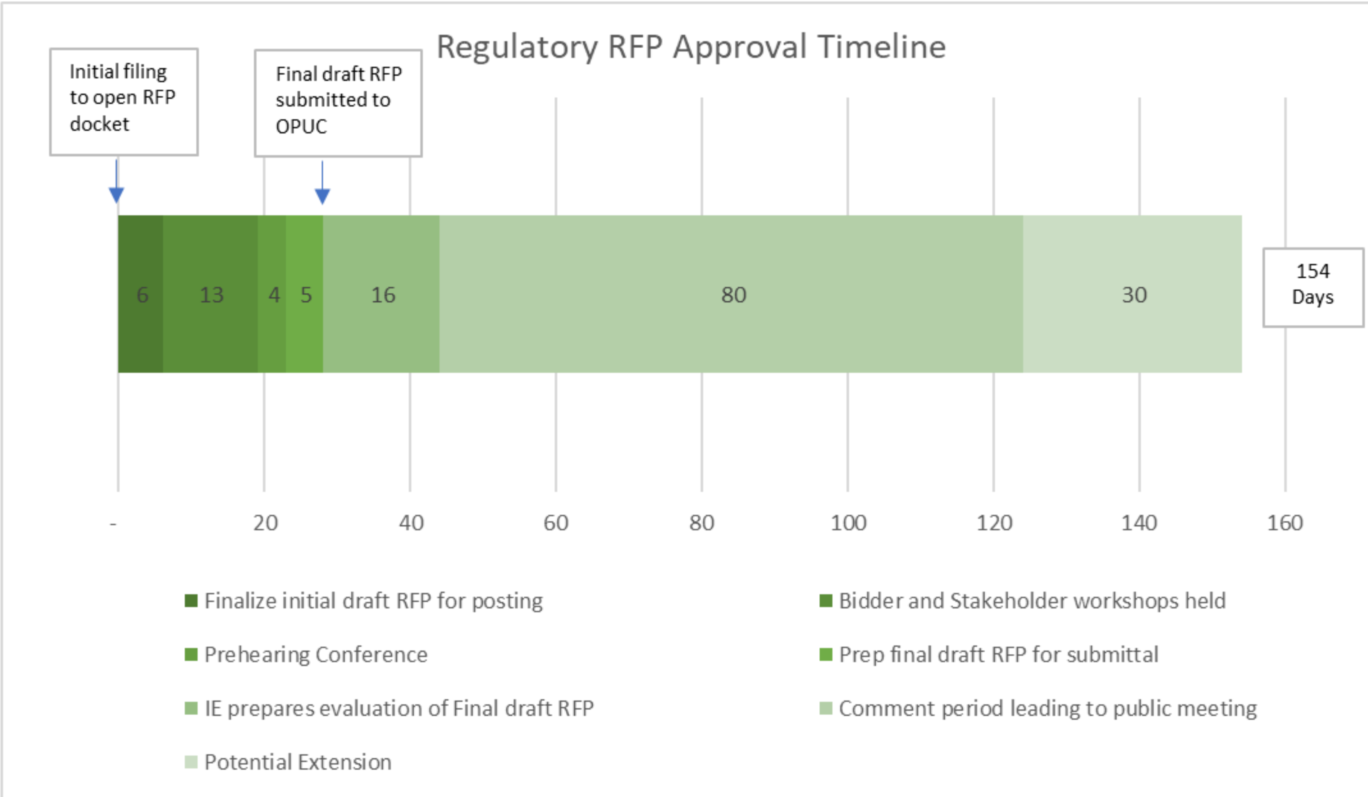
Notes:

- This estimate is based on PGE experience for utility process/evaluation in conjunction with the Final Rules.
- Scenarios assume additional 60 days to work with stakeholder's pre-issuance of IE RFP
- Work with IE assumes 30 days
- Regulatory RFP process begins with issuing the draft RFP, rules allow for a 30-day extension
- RFP Process is from issuance through final short list acknowledgement, at which point negotiations could begin



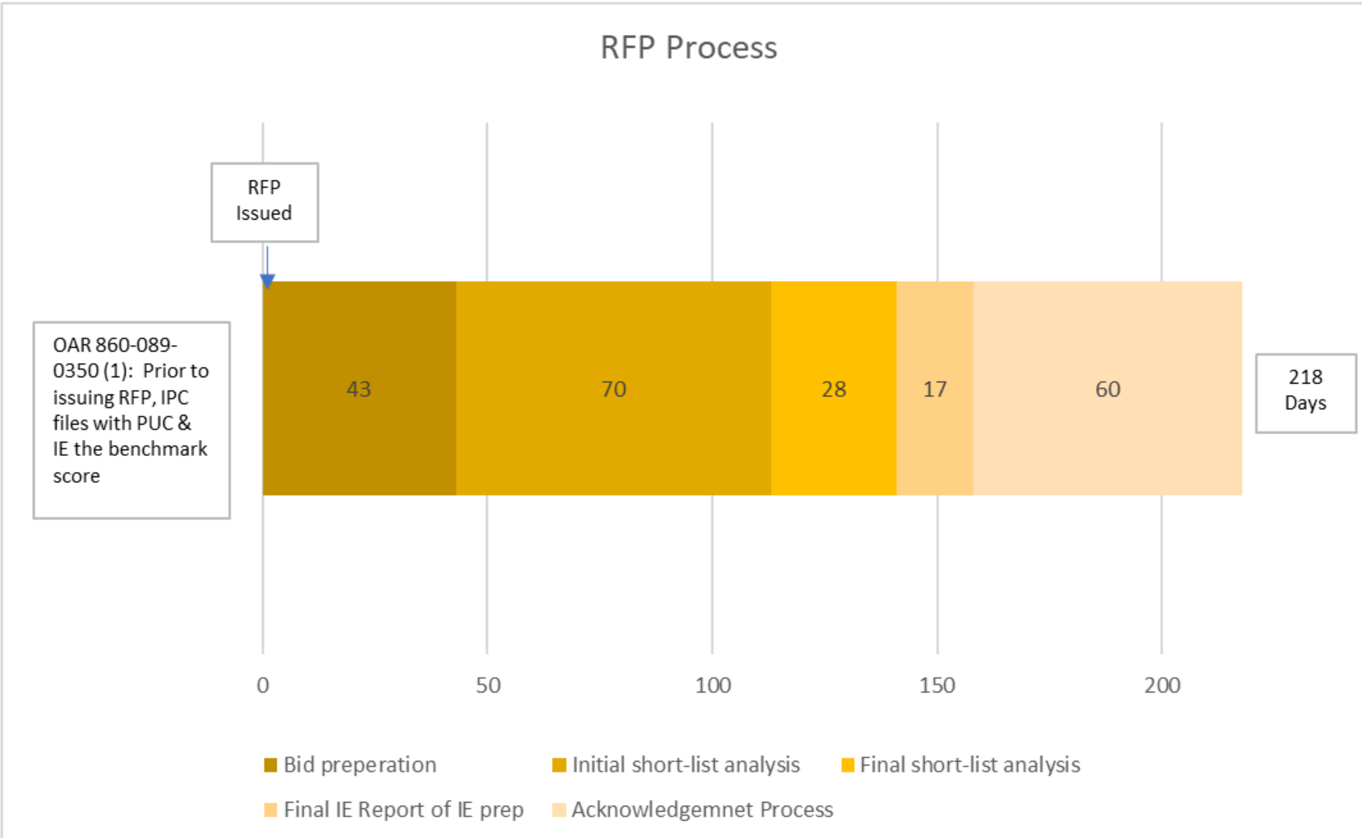
Notes:

OAR 860-089-200(1) - Prior to issuing an RFP, an electric company must engage the services of an IE to oversee the competitive bidding process. The electric company must notify all parties to the electric company's most recent general rate case, RFP, and IRP dockets of its need for an IE, and solicit input from these parties and interested persons regarding potential IE candidates.



Notes:

- OAR 860-089-250(1) - initial draft provided to all parties and interested persons in the electric company's most recent general rate case, RFP, IE selection, and IRP dockets.
- OAR 860-089-250(6) - The Commission will generally issue a decision approving or disapproving the draft RFP within 80 days after the draft RFP is filed. An electric company may request an alternative review period when it files the draft RFP for approval including a request for expedited review upon a showing of good cause. Any person may request an extension of the review period of up to 30 days upon a showing of good cause.



Notes:

OAR 860-089-350(1) Prior to the opening of bidding on an approved RFP, the electric company must file with the Commission and submit to the IE, for review and comment, a detailed score for any benchmark resource with supporting cost information, any transmission arrangements, and all other information necessary to score the benchmark resource. The electric company must apply the same assumptions and bid scoring and evaluation criteria to the benchmark bid that are used to score other bids.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-21-41

IDAHO POWER COMPANY

ATTACHMENT 2

IDAHO POWER.
An IDACORP Company

2021 All Source Request for Proposals (RFP) for Peak Capacity Resources

RFP Issued: June 30, 2021

RFP Response | August 11, 2021 | 4:00 p.m. Mountain Time

PowerAdvocate No. 116534

Idaho Power Company
P.O. Box 70
Boise, ID USA 83707

Table of Contents

1. Disclaimer

The information contained in this Request for Proposals (RFP) is presented to assist interested parties in deciding whether or not to submit a proposal. Idaho Power Company (IPC), an operating company subsidiary of IDACORP, Inc., is issuing this RFP to solicit formal proposals from qualified companies (each a Respondent) and does not represent this information to be comprehensive or to contain all of the information that a Respondent may need to consider in order to submit a proposal. None of IPC, its affiliates, or their respective employees, directors, officers, customers, agents and consultants makes, or will be deemed to have made, any current or future representation, promise or warranty, express or implied, as to the accuracy, reliability or completeness of the information contained herein, or in any document or information made available to a Respondent, whether or not the aforementioned parties knew or should have known of any errors or omissions, or were responsible for their inclusion in, or omission from, this RFP.

No part of this RFP and no part of any subsequent correspondence by IPC, its affiliates, or their respective employees, directors, officers, customers, agents or consultants shall be taken as providing legal, financial or other advice or as establishing a contract or contractual obligation. IPC reserves the right to request from Respondent information that is not explicitly detailed in this document, obtain clarification from Respondents concerning proposals, conduct contract development discussions with selected Respondents, conduct discussions with members of the evaluation team and other support resources as described in this RFP. The requirements specified in this RFP reflect those presently known. IPC reservices the right to vary, in detail, the requirements and/or to issue addenda to the RFP. In the event it becomes necessary to revise any part of the RFP, addenda will be provided to Respondents included in the current and applicable stage of the RFP.

IPC will, in its sole discretion and without limitation, evaluate proposals and proceed in the manner IPC deems appropriate. IPC reserves the right to reject any and all, or portions of any proposal submitted by Respondents for failure to meet any criteria set forth in this RFP or otherwise and to accept proposals other than the lowest cost proposal.

This RFP has been prepared solely to solicit proposals and is not a contract offer. This RFP is not binding on IPC. The only document that will be binding on IPC is an agreement duly executed by IPC and the successful Respondent (if any) after the completion of the evaluation process and the award and negotiation of an agreement. IPC reserves the right to reject any and all proposals submitted by Respondents. The issuance of this RFP does not obligate IPC to purchase any product or services offered by Respondent or any other entity. Furthermore, IPC may choose, at its sole discretion, to abandon the RFP process in its entirety. Respondents agree that they submit proposals without recourse against IPC, IDACORP Inc., any of IDACORP Inc.'s affiliates, or any of their respective employees, agents, officers, or directors for failure to accept an offer for any reason. IPC also may decline to enter into any agreement with any Respondent, terminate negotiations with any Respondent or abandon the RFP process in its entirety at any time, for any reason and without notice thereof. Respondents that submit proposals agree to do so without legal recourse against IPC, its affiliates, or their respective employees, directors, officers, customers, agents or consultants for rejection of their proposals or for failure to execute an agreement for any reason. IPC and its affiliates shall not be liable to any Respondent or other party in law or equity for any reason whatsoever for any acts or omissions arising out of or in connection with this RFP. Respondent shall conform in all material respects to all applicable laws, ordinances, rules, and regulations and nothing in this RFP shall be construed to require IPC or Respondent to act in a manner contrary to law. Except as otherwise provided in the rules and orders of the state of Idaho and Oregon Public Utilities Commissions (the Commission or Commission's), by submitting its proposal, a Respondent waives any right to challenge any valuation by IPC of its proposal. Respondent whose proposal may be selected in response to this RFP acknowledges that it assumes full legal responsibility for the accuracy, validity, and legality of the work provided in conformance with this RFP. By submitting its proposal, a Respondent waives any right to challenge any determination of IPC to select or reject its proposal. IPC reserves the right to accept the proposal in whole or in part, and to award to more than one Respondent. Furthermore, Respondent understands that any "award" by IPC does not obligate IPC in any way. IPC will not be obligated to any part unless and until IPC executes a definitive agreement between the parties.

Respondent will absorb all costs incurred in responding to this RFP, including without limitation, costs related to the preparation and presentation of its response. All materials submitted by the Respondent immediately become the property of IPC. Any exception will require written agreement by both parties prior to the time of submission.

In responding to this RFP, Respondent shall adhere to best business and ethical practices. Respondent shall adhere to IPC's Supplier Code of Conduct, available at www.idahopower.com.

Respondent is specifically notified that failure to comply with any part of this RFP may result in disqualification of the proposal, at IPC's sole discretion.

2. Purpose

2.1. BACKGROUND

Idaho Power Company, an operating company subsidiary of IDACORP Inc., is issuing this RFP to solicit formal proposals from Respondents for electric capacity resources (Products) to help meet IPC's peak electric energy needs in 2023.

IDACORP, Inc. is a holding company formed in 1998. Comprised of regulated and non-regulated businesses, its origins lie with Idaho Power, a regulated electric utility that began operations in 1916. Today, IPC is the largest regulated electric utility in the state of Idaho and IDACORP's chief subsidiary. IPC serves over 590,000 residential, business, agricultural, and industrial customers. The company's service area covers approximately 24,000 square miles, including portions of eastern Oregon. Learn more about Idaho Power at www.idahopower.com.

IPC currently serves its customers by supplying low-cost, reliable, and clean energy. Affordable, clean hydropower is the largest source of energy for customers. Power generation comes from a diverse set of resources that continues to meet a growing demand. For a more detailed description of current generation resources, please visit: www.idahopower.com/energy-environment/energy/energy-sources/.

IPC's service territory continues to experience customer growth and an increasing peak demand (load) for electricity. IPC anticipates sustained load growth that will require the procurement of new resources to meet peak summer demand and maintain system reliability. Additionally, recent changes in the regional transmission markets have constrained the transmission system external to the IPC service territory and impacted the ability to import energy from western market hubs for delivery to IPC's system. The addition of new resources to meet peak demand is critical to ensure IPC can continue to reliably meet the growing demands on its electrical system and serve its customers.

The need for additional capacity resources has been identified as early as Summer 2023 at approximately 80 megawatts (MW). Please refer to EXHIBIT D – Information on Most Valuable Hours for a more detailed description of the capacity need.

2.2. THE SOLICITATION

IPC intends to enter into agreement(s) to purchase Products for up to 80 MW of electric generating capacity delivered from resources that employ certain qualifying technologies under certain ownership arrangements. The eligible types of Products are described further in Section 3 of this RFP. Details on the proposal submission process and the proposal evaluation process are also described further in this RFP. Demand side measures are being evaluated outside of this RFP.

The process of issuing and responding to this RFP, evaluation and selection of proposals, and the negotiation and approval of the agreement(s) is known as the Solicitation. Respondents who are interested in participating in the Solicitation and submitting a proposal must first register via the third-party solicitation portal, PowerAdvocate, further described in Section 2.5 of this RFP. This RFP sets forth the terms and conditions by which IPC will perform the Solicitation. Respondent agrees to be bound by all the terms, conditions, and other provisions of this RFP and any addenda to it that may be issued by IPC. This RFP governs the Solicitation and supersedes any other written or oral form of communication between Respondents and IPC concerning the Solicitation.

2.3. REGULATORY CONTEXT

Execution of any purchase agreement will ultimately be subject to the Commission's approval. This could include, but is not limited to, approval of a certificate of public convenience and necessity (CPCN) application from IPC. IPC reserves the right to: 1) inform the Commission that IPC could not reach agreement with the Respondent of a selected resource; 2) request Commission approval of any agreements it enters into with successful Respondents (e.g., CPCN applications); and 3) to terminate any agreement if IPC fails to receive Commission approval of submitted agreements or applications. Respondent shall provide any and all information and documentation reasonably requested by IPC to support such applications and requests.

2.4. CONFIDENTIALITY

Respondent acknowledges and agrees that all information obtained or produced in relation to this RFP is the sole property of IPC and shall not be released or disclosed to any person or entity for any purpose other than providing a proposal to IPC without the express written consent of IPC. Respondent agrees not to make any public comments or disclosures, including statements made for advertising purposes, regarding this RFP to the media or any other party without prior written consent of IPC. In the event Respondent receives any inquiries regarding this RFP from the media or any other party, said inquiries shall be forwarded to IPC.

Respondents shall specifically designate and clearly label any and all material(s) or portions thereof, contained in their proposals, that they deem to contain proprietary information as "CONFIDENTIAL". Nonetheless, IPC reserves the right to release all proposals to its affiliates and such affiliates' agents, advisors, and consultants, for purposes of proposal evaluation. IPC will, to the extent required by law, advise each agent, advisor, or consultant that receives such claimed confidential information of its obligations to protect such information. In addition, all information, regardless of its confidential or proprietary nature, will be subject to review by the Commission and other governmental authorities and courts with jurisdiction, and may be subject to legal discovery. It is not IPC's intent to enter into any separate confidentiality, non-disclosure, or similar agreements as a condition to receiving a Respondent's proposal. However, if and when a proposal is advanced to the Initial Short List, the Respondent must execute a Mutual Nondisclosure & Confidentiality Agreement (Confidentiality Agreement) with IPC in advance of further discussions with and evaluation of the proposal by IPC. Respondents are directed to EXHIBIT I – Mutual Non-Disclosure Agreement for more detailed information.

2.5. SOLICITATION PORTAL AND RESTRICTION ON COMMUNICATIONS

IPC has opened a web-based portal hosted on the PowerAdvocate sourcing platform (the Portal). All information exchanged between the Respondent and IPC concerning the Solicitation must only be via the Portal from the time the Portal is open until it is closed by IPC. The Portal allows a Respondent to see only its own information and not the information of other Respondents.

IPC has the ability to communicate with Respondents through the Portal. Other than written communication through the Portal, Respondents are prohibited from communicating with IPC employees, representatives, staff, or Board Members regarding the Solicitation during the period in which the Portal is open.
Restricted communication includes, but is not limited to, "thank you" letters, phone calls, emails, and any contact that results in the direct or indirect discussion of the Solicitation and/or submitted proposals. Violation of this provision by Respondents or their agents may lead to disqualification.

The web link to the Portal hosted by PowerAdvocate is:

www.poweradvocate.com

Respondent is responsible for ensuring it has registered for, and posts documents to, the correct portal hosted by PowerAdvocate. The Respondent registering for access to the Portal must be a representative of the Respondent and counterparty with which IPC will engage in any future negotiations, and not consultants or attorneys for the Respondent.

Respondents who have completed the registration process and submitted the public Notice of Intent Form found at www.idahopower.com/about-us/doing-business-with-us/request-for-resources shall receive an email invitation from PowerAdvocate containing a link to the event.

Respondent must not disclose its participation in this Solicitation (other than by attendance at any meeting held by IPC with respect to the Solicitation) or collaborate on, or discuss with any other Respondent or potential Respondent bidding strategies or the substance of any proposal(s), including without limitation the price or any other terms or conditions of any proposal(s).

Questions regarding the Portal should be directed to:

PowerAdvocate Support
support@poweradvocate.com
+001.857.453.5800

2.6. SCHEDULE

The key milestones for the Solicitation and their currently scheduled dates are provided in Table 1 below.

Table 1 – Key Milestones for the Solicitation

Milestone	Date
Portal opened for interested party registration and communication	June 30, 2021
RFP and other Solicitation documents posted to the Portal	June 30, 2021
Respondent Intent to Bid Due	July 7, 2021
Pre-Bid Presentation Recording posted to the Portal	July 12, 2021
Deadline for Submittal of Questions, after which IPC may not respond	July 28, 2021 by 4 p.m. Mountain Time
Deadline for Proposal Submittal – Portal closed to further posting by Respondents, evaluation begins	August 11, 2021 by 4 p.m. Mountain Time

This schedule and documents associated with the Solicitation are subject to change at IPC's sole discretion at any time and for any reason. IPC will endeavor to notify Respondents of any changes to the Solicitation but shall not be liable for any costs or liability incurred by Respondents or any other party due to a change or for failing to provide notice or acceptable notice of any change. Respondents should factor this schedule and any changes thereto into their project development timelines and proposals.

Respondents should carefully review this RFP for questions, clarifications, defects, and questionable or objectionable materials. Comments and questions concerning clarifications, defects, and questionable or objectionable material **must be submitted through the Portal and must be submitted on or before the date and time specified in the above schedule.** IPC may not respond to questions submitted after this date. All questions and their applicable responses will be provided to Respondents via the Portal.

2.7. PRE-BID PRESENTATION AND RECORDING

IPC will not host an in-person live pre-bid meeting or webcast regarding the Solicitation due to concerns over potential technical difficulties in live hosting such a large event and fairness to Respondents from distant time zones. Instead, IPC will prepare a video recording concerning the RFP and the overall Solicitation process. The recording will include video of a presentation deck and audio of the speakers presenting the deck. The recording will be posted to the Portal on or before the date identified in the Schedule provided in Section 2.6 of this RFP. Viewing of the recording is not mandatory for Respondents.

3. Product Specifications

3.1. KEY PRODUCT SPECIFICATIONS

The key specifications for a subset of the Products eligible to be proposed in response to the RFP are presented in Table 2 below.

Table 2 – Key Product Specifications

	1	2	3	4	5
Product	**Energy Storage Project ("S")**	**Solar PV plus Storage Project ("PVS")**	**Wind plus Storage Project ("WS")**	**Energy Storage Component of a Solar PV plus Storage Project ("S-PVS")**	**Energy Storage Component of a Wind plus Storage Project ("S-WNS")**
Product Type	Asset Purchase			Partial Asset Purchase	
Ownership	IPC			IPC (Storage component only)	
Resource Status	Existing, or proposed new with preference for projects in late stage development with pending LGIA or SGIA				
Agreement	Existing resources under an Asset Purchase Agreement (APA), proposed new resources under a Build Transfer Agreement (BTA)				
Design Life (Years)	20	30	40	20	20
First Delivery	June 1, 2023				
Capacity	Min: 1 MW, Max: 80 MW				
Interconnection	Transmission (10 MW – 80 MW) or Distribution (1 MW – 10 MW) system of IPC				
Delivery Point	Within the boundary of the IPC Balancing Authority Area (BA), or outside with all necessary transmission rights to the BA				

	1	2	3	4	5
Product	**Energy Storage Project ("S")**	**Solar PV plus Storage Project ("PVS")**	**Wind plus Storage Project ("WS")**	**Energy Storage Component of a Solar PV plus Storage Project ("S-PVS")**	**Energy Storage Component of a Wind plus Storage Project ("S-WNS")**
Storage Duration	Minimum 4 hours				
Storage Cycles	Minimum 1 cycle per day				
Pricing	$ 000s on acquisition date, $ 000s per month under a construction completion management agreement (CCMA), $000s per year under an operation and maintenance services agreement (OMA), $/MWh charging energy price				
Price Escalation	None				
Other	Storage must be chargeable from the grid by IPC after expiration of the tax benefit recapture period.				

3.2. ADDITIONAL PRODUCT SPECIFICATIONS

IPC may also accept other Products that meet the ownership and electrical functionality criteria outlined in Table 2. Respondents who propose a product not specifically identified in Table 2 must provide applicable information, specifications, terms, etc. for evaluation purposes. Products that are not eligible include, but are not limited to; energy or capacity that is not electrical (for example, thermal energy storage without conversion to electric energy), energy or capacity that is not provided from a specific resource (a System Sale), renewable energy credits without the associated energy (Unbundled RECs), and financial instruments used to mitigate variable cost exposure without associated energy or capacity (Financial Firming).

Respondents whose proposals include Solar PV and/or Wind technologies are encouraged to configure the Solar PV and/or Wind resources to maximize energy delivery during hours that are most valuable to IPC. Information concerning the hours that are most valuable to IPC is provided in EXHIBIT D – Information on Most Valuable Hours attached hereto.

Proposals for new resources (a Project) to be owned by IPC must assume the parties will execute a build-transfer agreement (BTA), a construction completion management agreement (CCMA) and an operation and maintenance services agreement (OMA) for implementation of the Project. Under a BTA, the Respondent is responsible for all aspects of the development and construction of the Project, including but not limited to permitting, design, development, engineering, procurement, construction, interconnection, and all related costs up to achieving the to-be-agreed upon milestone which will not be earlier than mechanical completion or later than the date the Project is placed into service for tax purposes. After reaching the milestone, the Respondent will transfer ownership of the Project assets to IPC in exchange for a purchase price. Proposals that contemplate the transfer of 100% equity interests in a single member LLC are acceptable. After purchase, the Respondent will remain responsible for the completion of the Project pursuant to a CCMA. After the Project achieves commercial operation, the Respondent will perform operations and maintenance services under the OMA. Beginning at execution of the BTA and related agreements, the Respondent must post cash collateral or a letter of credit in the amounts specified in the BTA to secure its performance (Performance Security). The amount of Performance Security increases and decreases over the term of the Project development, construction, and operation phases.

Proposals for existing resources (a Plant) to be owned by IPC must assume parties will execute an asset purchase agreement (APA) and an OMA.

IPC will accept Project proposals that include a PPA for wind and solar, provided the proposal includes a BTA for the storage resource.

Respondents are directed to EXHIBIT E – Draft Form Term Sheet for more detailed information concerning the key terms and conditions of the BTA, CCMA and OMA agreements. Respondents are required to submit a redline of the Draft Form Term Sheet with their proposals. Respondents are also directed to EXHIBIT K – Draft Form Letter of Credit for reference. In such cases that the Respondent is successful, Respondent shall be responsible for furnishing a letter of credit in a format substantially similar to these forms included in this RFP. These forms shall be subject to review and acceptance by IPC in its reasonable discretion. Respondent shall deliver the required letter of credit no later than 30 days following any such notice of award of the Project.

4. Electric Interconnection

4.1. COST ESTIMATING

Respondent is responsible for understanding the electric transmission and distribution interconnection processes of IPC or other transmission providers, considering the durations and costs of those processes in its proposals, and successfully executing those processes to achieve coordination with IPC and delivery of the proposed Products to IPC on or before the dates identified in its proposed schedule for the resource.

Electric interconnection facilities consist of multiple components as defined below.

a) Interconnection Customer's Interconnection Facilities (ICIF) are all facilities and equipment (including the gen tie line) located between the resource and the Point of Change of Ownership. Respondent must submit resource-specific cost estimates of ICIF as part of its proposal and consider the cost of ICIF in its pricing.
b) Transmission Provider Interconnection Facilities (TPIF) connect the Interconnection Customer's Interconnection Facilities and facilitate the metering, relay and communications, etc. TPIF are all facilities owned, controlled or operated by the transmission Provider from the Point of Change of Ownership to the Point of Interconnection. These are facilities that IPC will own, and the Respondent will fund. Respondent must submit resource-specific cost estimates of TPIF as part of its proposal and consider the cost of TPIF in its pricing. To aid in consideration of the cost, an estimated cost for TPIF based on interconnection voltage level is provided below. If an interconnection study has been performed by the Transmission Provider that includes an estimate of TPIF, then the costs from that study should be used in lieu of these estimates.

Voltage	TPIF Estimated Cost (2021 $ 000s)
69 kV	$1,000
138 kV	$1,250

Voltage	TPIF Estimated Cost (2021 $ 000s)
230 kV	$1,800
345 kV	$2,500

c) Station Network Upgrades (SNU) are either new switchyards or additions to existing switchyards or substations that are built to interconnect the generator to IPC transmission or distribution system. SNUs become a component of the integrated IPC transmission or distribution system and are incorporated into IPC tariffs. Respondents are not required to provide cost estimates of SNUs.

d) Delivery Network Upgrades (DNU) are upgrades to IPC's transmission or distribution network that will be required for individual resources and groups of resources. These upgrades will be incorporated into IPC's transmission or distribution tariffs. Respondents are not required to provide cost estimates of DNUs.

If a Respondent has an active interconnection request, the Respondent must provide the interconnection request identifier(s) (the "queue position") associated with its resource in its proposal. If the resource identified in the proposal was in the queue but has since withdrawn, the Respondent should provide that queue position even though it is no longer active. **For Respondents that submit a generation interconnection request or transmission service request pursuant to IPC's Open Access Transmission Tariff (OATT) intending to receive interconnection or transmission service cost estimates for purposes of responding to this RFP, there may not be sufficient time to have studies performed and completed prior to bid selection**.

Based on information available from the interconnection request (if any) and/or studies and estimates performed by the Transmission Provider separate and apart from the RFP evaluation team (if available), the RFP evaluation team will determine Proposal-specific SNUs and DNUs and associated costs to include in the evaluation of a proposal or estimate the SNUs and DNUs if unavailable from the Transmission Provider. Proposals involving existing generation resources from which IPC currently purchases capacity and energy will not be burdened during proposal evaluation with any incremental electric interconnection or network delivery costs provided that IPC currently has sufficient transmission and distribution capacity to deliver the proposed energy to its load. Existing generation resources that IPC determines to have inadequate transmission or distribution capacity to deliver will be burdened with the estimated cost of purchasing additional transmission rights and/or SNUs and DNUs.

4.2. INTERCONNECTION STUDIES

The Transmission Provider function within IPC, separate and apart from the RFP evaluation team, and performs studies for Large Generation Interconnection Application (LGIA) requests (over 20 MW) and Small Generation Interconnection Application (SGIA) requests (under 20 MW). The studies are performed to determine the feasibility, cost, time to construct, and injection capability for the interconnection of an electric generating resource. Information concerning generator interconnection can be found at IPC's website [1] including information on PURPA Qualifying Facility (QF) Interconnections, Non-PURPA QF Interconnections, and Facility Connection Requirements. IPC posts the results of these studies on its OASIS website.[2]

[1] www.idahopower.com/about-us/doing-business-with-us/generator-interconnection/
[2] www.oasis.oati.com/ipco/.

The transmission and distribution systems are interrelated and generation injection at one point on the systems may change the injection capability at other points. The generation injection capability assumed by the Respondent for purposes of a proposal may change when the Transmission Provider performs specific resource and resource portfolio interconnection studies. For purposes of aiding Respondents in determining points of interconnection and delivery, IPC has identified areas on the IPC system that may have relatively high injection capability and relatively low cost and time to construct if studied by the Transmission Provider. These areas are identified in EXHIBIT C – Information on Preferred Locations of this RFP.

If and when a proposal is selected for the Initial Short List and it is for a new resource that will be interconnected to the IPC BA, it may be studied by IPC per IPC's generation interconnection process. Respondents will be notified if their proposed resource will be studied and the Respondents must provide the site control, monetary deposits and other information required under the IPC generator interconnection process. When the study process reaches the Facilities Study phase, the Respondent will be responsible for continued compliance to bring the resource through the balance of the IPC interconnection process and execute an interconnection agreement.

Upon completion of the Facilities Study, the estimated costs of the SNU and DNU resulting from the study (if any) will be used by IPC in further evaluation of the proposal and determination if the Respondent will be selected for the Final Short List and invited to negotiate an agreement with IPC.

For Final Short List resources that will be owned in full or in part by IPC, IPC anticipates that it will declare them as Network Resources of IPC and that IPC will bear the cost of any network transmission service on IPC's system (whether or not procured under the OATT) for a resource that is ultimately contracted and achieves commercial operation.

5. Additional Requirements

5.1. DATA AND CYBER SECURITY

A proposal must comply with the provisions of Presidential Executive Order 13920 (E.O. 13920) issued May 1, 2020, titled *Securing the United States Bulk-Power System* (BPS) which (among other things) prohibits any acquisition, importation, transfer, or installation of BPS electric equipment by any person or with respect to any property to which a foreign adversary or an associated national thereof has any interest, that poses an undue risk to the BPS, the security or resiliency of U.S. critical infrastructure or the U.S. economy, or U.S. national security.

All design and implementation details must follow electrical industry best practices for cyber security as well as all applicable regulatory requirements pertaining to the security of electric system assets. In response to EXHIBIT A – Information for Qualitative Evaluation of this RFP, Respondents must generally describe their cyber security requirements, practices, and policies. Any additional IPC specific requirements will be addressed during the RFP review and contracting process, pursuant to EXHIBIT I – Mutual Non-Disclosure Agreement. Respondent must state that any and all equipment utilized in the proposed resource will not be procured through an Office of Foreign Assets Control (OFAC) designed entity or otherwise be comprised of equipment prohibited for use by electric utilities in the United States.

5.2. PURCHASING RESTRICTIONS/PROHIBITED TECHNOLOGY

Pursuant to Section 889(a)(1)(B) of the John S. McCain National Defense Authorization Act for Fiscal Year 2019, a Respondent must be able to represent in its agreement with IPC that the Respondent does not and/or will not use any telecommunications equipment, system, or service (or as a substantial or essential component of any system or as or critical technology of any system) made by any of the following companies, or any subsidiary or affiliate thereof (including companies with the same principal word in the name, e.g., Huawei or Hytera: Huawei Technologies Company; ZTE Corporation; Hytera Communications Corporation; Hangzhou Hikvision Digital Technology Company; or, Dahua Technology Company (collectively, Prohibited Technology).
Prohibited Technology may include, but is not limited to, video/monitoring surveillance equipment/services, public switching and transmission equipment, private switches, cables, local area networks, modems, mobile phones, wireless devices, landline telephones, laptops, desktop computers, answering machines, teleprinters, fax machines, and routers. Prohibited Technology does not include telecommunications equipment that cannot route or redirect user data traffic or permit visibility into any user data or packets that the equipment transmits or handles.

5.3. SMALL BUSINESS AND SMALL DISADVANTAGED BUSINESS PROGRAM

IPC is committed to the implementation of a Small and Disadvantaged Business Program. It is the intent of IPC that small business concerns and small businesses owned and controlled by socially and economically disadvantaged individuals have the opportunity to participate in the performance of contracts awarded by IPC. Consequently, we request that you indicate your eligibility as a small business based upon the regulations in Title 13, Code of Federal Regulations, Part 121. If in doubt, consult the Small Business Administration Office in your area.

6. Proposal Format and Submittal

6.1. SUBMISSION OF PROPOSALS

A proposal is considered the aggregate of the information uploaded by a Respondent to the Portal (Information). The Information is in the form of data entered directly into cells in a spreadsheet located on the Portal (Proposal Entry Form or PEF) and subsequently uploaded to the Portal by the Respondent, and other written documents that are uploaded to the Portal. The Portal is designed to accept the majority of the Information as data entered into the PEF with data entry restricted to only certain eligible types and values. The purpose is to ensure Information is entered consistently across all Respondents and proposals such that IPC can consistently, fairly and quickly organize the Information and evaluate the proposals and minimize the amount of written (e.g., PDF, DOC) documents that IPC must review and interpret.

Respondents are strongly advised to carefully review Exhibit E – Draft Form Term Sheet and the Technical Specifications (Exhibit F – BESS Technical Specification, Exhibit G – Solar Technical Specification, and Exhibit H – Wind Technical Specification) relevant to their proposed products prior to uploading information to the Portal. If and when a Respondent is selected for negotiation of an agreement, IPC will utilize the Information submitted to populate the relevant portions of the agreements for that Respondent. Respondents should upload information with the understanding that it will ultimately result in binding contract terms.

6.2. BID FEES

A Respondent is required to submit to IPC a non-refundable fee of $10,000 with each proposal submitted (Evaluation Fee). The purpose of the Evaluation Fee is to encourage submission of well-developed and viable proposals and to offset the cost to IPC for evaluation of proposals. For the purpose of assessing an Evaluation Fee, a proposal is generally defined as follows.

- A single capacity construction phase of a resource at one site = one proposal
- Different capacity, initial delivery year or price from the same site = different proposal
- Different technology from the same site = different proposal
- Different Product from same site = different proposal
- Different site = different proposal

IPC may deem a proposal that does not satisfy the requirements for a single proposal as multiple proposals each of which would require a separate Evaluation Fee. If IPC deems a Respondent's proposal to be multiple proposals, IPC will notify the Respondent and allow it to elect to pay the incremental Evaluation Fee or to revise its proposal to comply with IPC's requirements for a single proposal.

A Respondent that has its proposal selected for the Final Short List and is invited to begin negotiation of an agreement must submit an additional fee in an amount equal to $1/kW of proposed resource capacity (a Supplemental Fee) to IPC prior to commencement of negotiations. For example, a proposal for a resource with a proposed capacity of 80 MW would pay a Supplemental Fee of $80,000 (e.g., 80 MW Project * $1/kW = $80,000). The purpose of the Supplemental Fee is to ensure good faith submissions and negotiations by the Respondent and to offset the costs that IPC will incur while reviewing proposals and negotiating an agreement. The Supplemental Fee will not be refundable.

6.3. PROPOSAL NAMING

A Respondent must generate a unique name for each of its proposals (Proposal Code) by selecting and entering into the PEF where indicated the Product Type, Proposal Name, Delivery Level and whether the facility is new or existing. The resulting Proposal Code must thereafter be used by the Respondent when referring to the proposal and must be inserted into the file name of each document for the proposal uploaded by the Respondent. The purpose of the Proposal Code is to allow IPC to more easily identify and differentiate among proposals and documents particularly if the volume of proposals received is relatively large.

6.4. PROPOSAL WRITTEN DOCUMENTS

Written documents must be text-searchable PDF (portable document format, non-zipped) and must contain documents reproduced directly from the native document (i.e., Word, Excel, MicroStation, AutoCAD). Scanned images and documents will be considered irregular and may be rejected.

6.5. PROPOSAL SUBMISSION REQUIREMENTS

Exhibits to this RFP summarize the Information that must be uploaded by Respondents to the Portal. These include EXHIBIT A – Information for Qualitative Evaluation and EXHIBIT B – Information for Quantitative Evaluation attached hereto. Respondents are directed to the individual tabs in the Portal to ensure Respondent reviews all of the information and the specific type and level of detail that must be provided.

6.6. FIRM PROPOSAL

Each proposal shall be firm, not subject to price escalation, and binding for one hundred eighty (180) days from the date the proposals are due under this RFP.

6.7. TAXES

Respondents are responsible for the payment of all sales, conveyance, transfer, excise, real estate transfer, business and occupation, and similar taxes assessed with respect to or imposed on either party in connection with a proposed agreement.

6.8. INSURANCE

The insurance requirements that must be met by Respondent are summarized below. This summary is provided for information only. Respondent is directed to the EXHIBIT E – Draft Form Term Sheet for details concerning the specific requirements. If a conflict arises between this summary, the requirements in the Draft Form Term Sheet, or executed agreement between Respondent and IPC, the executed agreement shall govern.

This summary is for information only. At its sole cost and expense, Respondent shall maintain (and cause each of its agents, independent contractors, and Subcontractors at any tier performing any services on the project to maintain) the following insurance, including but not limited to:

- Workers' Compensation Insurance with limits of not less than those required by applicable statutes.
- Employer's Liability Insurance. When permitted by law, the insurance policies required shall contain waivers of the insurer's subrogation rights against IPC. Respondent shall reimburse IPC for any costs (including self-insured tax audit assessments) incurred in the event Respondent maintains an uninsured status within the state of Idaho.
- Business Automobile Liability Insurance.
- Commercial General Liability Insurance applicable to all premises and operations, including without limitation: (i) bodily injury, (ii) property damage, (iii) contractual liability coverage covering its obligations of indemnity and defense, (iv) products and completed operations, (v) independent contractors, and (vi) personal and advertising injury. Such insurance shall provide for occurrence-based coverage and shall have such other terms, conditions, and endorsements of coverage as are deemed prudent by IPC from time to time.
- Professional Liability Insurance or Errors and Omissions Insurance, including without limitation, coverage for claims of financial loss due to error, act, or omission of Respondent or Respondents employees, officers, equity owners, subcontractors at any tier, or agents. Professional Liability Insurance shall be maintained for a minimum of two-years beyond the date of expiration of and executed or the agreement otherwise terminated.
- IP (Intellectual Property/Patent) Insurance covering infringement of copyrights, trademarks, and patents, and misappropriation of trade secrets.
- Fidelity Insurance naming IPC as Loss Payee, for losses arising out of, or in connection with, any fraudulent or dishonest acts, including without limitation computer fraud, committed by Respondent or Respondent's employees, officers, equity owners, Subcontractors at any tier, or agents, acting alone or with others, including losses of property and funds in their care, custody, or control.

- Contractor's Pollution Liability Insurance. Respondent, and Respondent subcontractors or their respective agents or employees are performing services under an executed agreement with environmental hazards maintains a "Claims Made" policy under this such insurance or its replacement insurance shall have a retroactive date of no later than the effective date of the agreement. Such insurance policy or its replacement policy shall provide either a minimum of two-years extended reporting period coverage after completion of all services, or a period equal to the maximum time under the State of Idaho statute of limitations existing on the effective date for potential claims under such insurance, whichever is longer. The policy must also provide the following:
    - Coverage for defense, reimbursement, and indemnity obligations assumed by Respondent under the and executed agreement related to claims, damages, liabilities, losses, demands, expenses, suits, judgments, penalties, fines and costs, including without limitation, investigative costs, settlement costs, court costs at all levels, and attorneys' and expert witness fees and expenses;
    - Coverage for any demands for environmental cleanup costs related to Respondents services under the executed agreement;
    - Coverage for the presence, discharge, dispersal, release or escape of smoke, vapors, soot, fumes, acids, alkalis, toxic chemicals, liquids or gases, waste materials or other irritants, contaminants or pollutants, silt or sediment into or upon land, the atmosphere or any watercourse or body of water (Pollution Conditions) emanating from or affecting any location, whether or not owned, leased, occupied or otherwise controlled by IPC, to the extent such Pollution Conditions are caused by Respondent, its employees, and agents;
    - Coverage for bodily injury, sickness, disease, mental anguish or shock sustained by any person, including death, and medical monitoring;
    - Coverage for physical injury to, or destruction of tangible property of, parties other than the insured including the resulting loss of use and diminution in value thereof; loss of use, but not diminution in value, of tangible property of parties other than that belonging to the insured that has not been physically injured or destroyed;
    - Coverage for transportation and non-owned disposal site (with no sunset clause/restricted coverage term) (if applicable);
    - Property damage to include natural resources damage; and
    - No exclusions for asbestos, lead paint, silica or mold/fungus.

Coverage shall apply to sudden and non-sudden Pollution Conditions, provided such conditions are not naturally present in the environment in the concentration or amounts discovered, unless such natural condition(s) are released or dispersed as a result of the performance of covered operations. Respondent additionally agrees to name IPC as an additional insured and to provide waiver of subrogation against IPC an to furnish insurance certificates, showing Respondents compliance.

- Cyber Liability, Network Security, Data Breach Protection and/or Similar Privacy Liability Insurance. In the event that Respondent will have access to any restricted information of IPC, its clients, customers, employees, prospective employees, or other third parties, whether protected or not by any local, statutory, federal or other governing legislation(s) or regulation(s), Respondent shall maintain cyber liability, network liability, data breach or similar privacy liability insurance covering actual and/or alleged acts, errors or omissions committed by Respondent, its employees, contractors or agents. For purposes of this RFP, "Restricted Information" means any confidential or personal information that is protected by law or policy and that requires the highest level of access control and security protection, whether in storage or in transit, including without limitation, personal identity information (PII), protected health information (PHI), electronic protected health information (ePHI) protected by Federal Health Insurance Portability and Accountability Act legislation, credit card data regulated by the Payment Card Industry (PCI), passport numbers, passwords providing access to restricted data or resources, information relating to an ongoing criminal investigation, court-ordered settlement agreements requiring non-disclosure, information specifically identified by contract as restricted, and other information for which the degree of adverse affect that may result from unauthorized access or disclosure is high. Such insurance shall expressly provide coverage for the following perils up to the full limit of coverage with no sublimit:

- Unauthorized use/access of a computer system or database;
- Defense of any regulatory or governmental action involving a breach of privacy or similar rights;
- Failure to protect from disclosure Restricted Information;
- Notification and remedial action costs (such as **credit monitoring)** in the event of an actual or perceived computer security or privacy breach; and
- Denial of electronic access, electronic infection, and electronic information damage, whether or not required by law.

Such insurance shall extend to cover damages arising out of any actual or alleged act(s), error(s) or omission(s) of any individual when acting under Respondent's supervision, direction, or control. Such insurance shall provide coverage on a worldwide basis. Respondent and its insurer(s) shall waive rights of recovery against IPC for any benefits under Respondents cyber-risk, data breach protection or similar privacy liability insurance.

- Cargo and Property Insurance. If Respondent, Subcontractor at any tier, or their respective agents or employees are transporting and/or storing IPC materials or equipment, Contractor shall provide Cargo Insurance and/or Property Insurance (as applicable) covering physical loss or damage, naming IPC as Loss Payee, arising out of, or in connection with, any loss associated with transportation or storage of IPC equipment or material while in the care, custody, or control of Contractor (or its Subcontractors at all tiers). The declared value of the Cargo and/or Property Insurance shall be based on the replacement value of the property in question.
- Insurance required shall be primary and non-contributory and:
  - Be issued on a U.S. policy by one or more carriers acceptable to IPC and licensed to do business in the state where services are rendered;
  - Except as to Workers' Compensation Insurance, Employer Liability Insurance, and Professional Liability Insurance, name IPC as an additional insured or losspayees, as its interests may appear;
  - Not be able to be canceled or materially changed unless IPC is given written notice of such cancellation or change at least thirty (30) days in advance;
  - Provide for severability of interests;
  - Waive all right of subrogation against additional insureds and IPC, its members, officers, employees, agents, and the successors in interest of the foregoing; and
  - Shall not be limited to "ongoing" operations. Respondent shall pay for all deductibles.
- If approved in advance by IPC in writing, Respondent may use a combination of Umbrella/Excess and Primary limits of insurance to provide coverage up to the required amount.

- Upon execution of an agreement, Contractor shall provide IPC with a certificate of insurance indicating all coverages required hereunder, and copies of all policies if requested by IPC.

Respondent agrees to carry and keep insurance in full force during the term of any agreements sufficient to fully protect IPC from all damages, claims, suits and/or judgments including, but not limited to, errors, omissions, violations, fees and penalties caused or claimed to have been caused by, or in connection with the performance or failure to perform under the agreements by Respondent, Respondent's agents or employees, a Respondent's Subcontractor(s), or its agents or employees. Should the Minimum Insurance Requirements of IPC change, the Respondent shall be notified in writing and Respondent shall have sixty (60) days to meet the new requirements. Should the new requirements add materially to Respondent's cost, Respondent may notify IPC and request adjustment in Respondent's compensation commensurate with the increase or decrease in Respondent's cost to achieve the new requirements.

6.9. FINANCIAL AND CREDIT INFORMATION

Respondent must provide a written response and associated documents in response to the Counterparty Financial Questionnaire. Details are further described in EXHIBIT J - Counterparty Financial Questionnaire of this RFP.

6.10. EXCEPTIONS TO THE DRAFT FORM TERM SHEET

Respondents must provide proposals and pricing that are consistent and compliant with EXHIBIT E – Draft Form Term Sheet for the proposed resource type. To the extent that the validity of a Respondent's proposal and/or the Respondent's ability to execute an agreement is contingent upon material changes to the language in EXHIBIT E – Draft Form Term Sheet, the Respondent should specifically identify the terms they propose to change in the form of a redline markup and submit the redline with its proposal. To the extent that a Respondent wishes to propose changes the Draft Form Term Sheet that, if accepted by IPC, would reduce the Respondent's proposed pricing the proposal should specifically identify in the redline such changes and the associated price reduction. To the extent practicable, Respondents should develop exhibits, schedules, attachments and other supplemental documents required by the Draft Form Term Sheet in the redline. Respondents proposing to sell existing generation facilities should propose in the redline changes to Exhibit E of this RFP for the proposed resource type reflecting the terms and conditions on which their proposal is based.

The proposed changes must be specific and include a detailed explanation and supporting rationale for each. General comments, drafting notes and footnotes such as "parties to discuss" will be disregarded and not negotiated. Exceptions to the EXHIBIT E – Draft Form Term Sheet requested by a Respondent will be reviewed as part of IPC's qualitative evaluation of the proposal.

6.11. EXCEPTIONS TO THE TECHNICAL SPECIFICATIONS

Respondents that propose a resource for IPC ownership must provide proposals and pricing that are consistent and compliant with the applicable technical specifications provided as Exhibits to this RFP ("Technical Specifications"). To the extent that the validity of a Respondent's proposal and/or the Respondent's ability to execute an agreement is contingent upon material changes to the language in the Technical Specifications, the Respondent must specifically identify the specifications it proposes to change in the form of a redline markup to the Technical Specification and submit the redline with its proposal. To the extent that a Respondent wishes to propose changes to the Technical Specification that, if accepted by IPC, would reduce the Respondent's proposed pricing the Respondent should specifically identify in the redline such changes and the associated price reduction. To the extent practicable, Respondents should develop exhibits, schedules, attachments and other supplemental documents required by the Technical Specification in the redline.

The proposed changes must be specific and include a detailed explanation and supporting rationale for each. General comments, drafting notes and footnotes such as "parties to discuss" will be disregarded and not negotiated. Exceptions to the Technical Specifications requested by a Respondent will be reviewed as part of IPC's qualitative evaluation of the proposal.

6.12. EXCEPTIONS TO THE DRAFT FORM LETTER OF CREDIT

Respondents that propose a resource for IPC ownership must provide proposals and pricing that are consistent and compliant with the EXHIBIT K - Draft Form Letter of Credit. To the extent that the validity of a Respondent's proposal and/or the Respondent's ability to execute an agreement is contingent upon material changes to the language in the Draft Form Letter of Credit, the Respondent should specifically identify the terms they propose to change in the form of a redline markup to EXHIBIT K - Draft Form Letter of Credit and submit the redline with its proposal. To the extent that a Respondent wishes to propose changes to the Draft Form Letter of Credit that, if accepted by IPC, would reduce the Respondent's proposed pricing the proposal should specifically identify in the redline such changes and the associated price reduction.

The proposed changes must be specific and include a detailed explanation and supporting rationale for each. General comments, drafting notes and footnotes such as "parties to discuss" will be disregarded and not negotiated. Exceptions requested by a Respondent will be reviewed as part of IPC's qualitative evaluation of the proposal.

6.13. CLARIFICATION OF PROPOSALS

While evaluating a proposal, IPC may request clarification or additional information from the Respondent about any item in its proposal. Such requests will be sent via the Portal by IPC and the Respondent must provide a response via the Portal back to IPC within five (5) business days, or IPC may deem the Respondent to be non-responsive and either suspend or terminate further evaluation of its proposal. Respondents are encouraged to provide an alternate point of contact to ensure a timely response to clarification requests.

6.14. ADDENDA TO RFP

Any additional responses required from Respondents as a result of an Addendum to this RFP shall become part of each proposal. Respondents must acknowledge receipt of and list all Addenda where indicated in the PEF.

7. Proposal Evaluation, Negotiation and Approval

7.1. EVALUATION PROCESS

The proposal evaluation process will include both qualitative and quantitative components.

The evaluation process begins with a screen to identify and remove from further evaluation proposals that are incomplete or do not comply with the basic requirements of the Solicitation (Threshold Screen). Examples of situations where a proposal fails the Threshold Screen include, but are not limited to, 1) the proposed product is not compliant with the Product definitions, 2) a substantial number of data fields in the PEF are incomplete, 3) key Information necessary to complete a comprehensive evaluation have not been uploaded.

Proposals that pass the Threshold Screen will then enter a detailed qualitative and quantitative evaluation. In evaluating proposals, IPC, in its sole discretion, will give weight and importance to the evaluation criteria listed below:

- Project Feasibility;
- Project Capability;
- Counterparty Profile;
- Community Stewardship;
- Price and Overall Cost to IPC; and
- Any other factors deemed appropriate by IPC.

7.2. ADDITIONAL RIGHTS

IPC may, in its sole discretion, at any time during the Solicitation:

1. Appoint evaluation committees to review proposals, seek the assistance of outside technical experts and consultants in proposal evaluation, and seek or obtain data from any source that has the potential to improve the understanding and evaluation of the responses to this RFP.
2. Revise and modify, at any time before the Deadline for Proposal Submittal, the factors it will consider in evaluating proposals and to otherwise revise or expand its evaluation methodology.
3. Hold interviews and meetings to conduct discussions and exchange correspondence with either all Respondents or only those with proposals that IPC elects to select for detailed discussions (Initial Short Listed Proposals) in order to seek an improved understanding and evaluation of an individual Respondent's proposal.
4. Issue a new RFP.
5. Cancel or withdraw the entire RFP or any part thereof.

7.3. ACCEPTANCE AND REJECTION OF PROPOSALS

IPC may or may not award an agreement after analysis and evaluation of the proposals. IPC reserves the right to reject any and all proposals, to waive minor formalities and irregularities, and to evaluate the proposals to determine which, in IPC's sole judgment, represents the best value for the Products requested.

7.4. AGREEMENT NEGOTIATIONS

In anticipation of an award, there will be a period of negotiations to finalize the agreement(s) between the parties. An agreement, including all terms, conditions, exhibits, and attachments must be executed by both IPC and the successful Respondent in order to create a binding enforceable agreement between IPC and the successful Respondent.

7.5. EXCLUSIVITY

If and when a proposal is selected for the Final Short List, from that date through the date of execution by both Parties of an agreement, the Respondent and/or its affiliates shall not execute an agreement with any other party for the sale of the proposed Product(s) such that the Respondent would no longer be able to provide the Products proposed in the proposal.

7.6. PUBLICITY

The Parties intend to issue joint public announcements, in the form of press releases, case studies, and/or other materials, containing content mutually agreed to by the Parties, upon execution of the agreements. Neither party shall use the name, logo, or any other indicia of the other party in any public statement, press release, other public relations or marketing materials, the identity of the other party, or any underlying information with respect to the agreement(s) at any time without the prior written consent of the other party, which it may withhold in such other party's sole discretion. Prior to making any such permitted use, each party shall provide for the other party's review and approval any publicity materials. Any and all goodwill from use of IPC's name, logo, or indicia will inure to IPC's sole and exclusive benefit.

7.7. COMMISSION APPROVAL

As stated previously in Section 2.3, execution of an agreement will ultimately be subject to Commission approval.

7.8. ENTIRE RFP

This RFP and all Exhibits, Attachments, Datasheets, Forms, and Addenda within the Portal event are incorporated herein by this reference and represent the final expression of this RFP. Only information supplied by IPC in writing through the parties listed herein or by this reference made in the submittal of this RFP shall be used as the basis for the preparation of Respondents proposals.

EXHIBIT A – Information for Qualitative Evaluation

A summary of the information that must be uploaded to the Portal by Respondents for purposes of the qualitative evaluation is provided below. The required information differs among the product types. **This is provided for information only. Respondents are directed to the Portal to review all of the information and the specific type and level of detail that must be provided for each product type. That level of detail is not provided in this Exhibit. In the case of conflict between this summary and the detail identified in the Portal, the detail identified in the Portal shall govern.**

PROJECT FEASIBILITY

1. Proposals must describe the resource technology including a description of key aspects, features, benefits, drawbacks, and history of its development and current status of deployment for utility scale operations.
2. Proposals must include a description of 1) status of major equipment procurement for the solar, wind and storage components, where applicable, 2) engineering, procurement, and construction bids and awards, 3) project/asset useful life, and 4) defect and performance warranty terms of solar and/or storage systems.
3. Proposals must state a point of delivery which meets the requirements for the proposed Product as specified in the Technical Specification section of the RFP.
4. Proposals for transmission connected resources must include documentation showing that the resource is on track to achieve interconnection by the date indicated in Respondent's project schedule. Proposals must also include documentation that the Respondent has estimated and included the costs for Interconnection Customer's Interconnection Facilities and Transmission Provider Interconnection Facilities in its proposed pricing.
5. Proposals for distribution connected resources must include documentation showing that the resource is on track to achieve interconnection by the date indicated in the Respondent's project schedule. Proposals must also include documentation that the Respondent has estimated and included the costs for Interconnection Customer's Interconnection Facilities and Transmission Provider Interconnection Facilities in its proposed pricing.
6. Proposals involving wind resources must include nodal economic analyses or curtailment analysis under base case (n-1) and outage scenarios (n-x) showing expected unit economic metrics (including congestion impacts on: capacity factor, produced energy, and generation revenue) for the project at the proposed delivery points.
7. Proposals must include proof of site control satisfactory to IPC. Proof of site control includes copies of title, lease, option to lease documents proving control is/can be established per the date specified in the Respondent's project schedule.
8. Proposals involving existing resources must describe any major current and/or historical operational issues, root causes and mitigation and any capital improvements that are necessary to ensure reliability.
9. Proposals must include a realistic and attainable project plan and schedule considering all permits and approvals, supply chain, site acquisition, interconnection, and transmission. The project plan must describe Respondent's approach for completing the project.

10. Proposals must include the Exhibit E - Draft Form Term Sheet relevant to the product being proposed with changes requested by Respondent (if any) shown in redline consistent with the Exceptions to Exhibit E - Draft Form Term Sheet requirements stated in the RFP.
11. Proposals must include the Exhibit K - Draft Form Letter of Credit relevant to the product being proposed with changes requested by Respondent (if any) shown in redline consistent with the Exceptions to Exhibit E - Draft Form Term Sheet requirements stated in the RFP.
12. Proposals must include the Technical Specifications relevant to the product being proposed with changes requested by Respondent (if any) shown in redline strikeout consistent with the Exceptions to Technical Specifications requirements stated in the RFP.
13. Proposals must include the Attachment A and/or Appendix A of the applicable Technical Specifications relevant to the product being proposed with Preferred Vendors of the major equipment suppliers of the Respondent's project marked or specified.
14. A proposal must state whether or not it is contingent on any other proposal submitted by the Respondent. For example, a proposal for implementation of a solar plus storage resource at a site and a separate proposal for implementation of a wind plus storage resource at the same site are contingent on one another (implementation of one precludes implementation of the other).
15. Proposals must include a financing plan for the proposed resource. Respondent will be scored on the credibility of its plan to raise all tranches of capital needed to successfully close on both construction and permanent financing, which may include the following: debt, tax equity related to accelerated tax deprecation (5 year MACRS); tax equity for the ITC and/or application for the Treasury's Grant-in-lieu of ITC Program (if applicable), and Respondent's own equity.
16. Proposals for solar plus storage or wind plus storage resources must provide documentation that the energy storage system is integrally connected to the functioning of the associated solar or wind generation facility and that the energy storage system will be exclusively charged with energy from the associated solar or wind generation facility for the first five (5) or more years of operation. Documentation must also be provided that the current "beginning of construction" IRS guidance will be met such that the resource will qualify for the greatest potential investment tax credit under federal tax law. Documentation must also be provided that if and to the extent that future federal tax law changes result in increased tax advantages to the resource that a share of such advantages will be quantified and passed through to IPC.

PROJECT CAPABILITY

17. Proposals for solar plus storage resources must include a forecast of the expected annual energy output of the resource performed using PVSyst or equivalent, and a guaranteed annual output as a percentage of forecast. Resources will be subject to annual review of metered output to determine compliance with guarantee.
18. Proposals for wind plus storage resources must include a forecast of the expected annual energy output of the resource performed. Proposals must include expected (p50, p90 and p99) capacity factors, including hourly shapes (actual or based on weather data) including at least one output file for the performed analysis.

19. Proposals involving storage must state a maximum storage duration.
20. Proposals involving storage must state the allowed storage cycles per day.
21. Proposals involving storage must state the round-trip efficiency.
22. Proposals involving storage must state the annual baseline degradation and variable degradation per cycle.
23. Proposals involving storage must state the time required to charge the resource from minimum to maximum state of charge.
24. Proposals involving storage must include a Capacity Guarantee. Resources will be subject to annual test with test results adjusted to guarantee conditions to determine compliance with guarantee.
25. Proposals involving storage must include both a guaranteed equivalent forced outage rate (EFOR) and a guaranteed equivalent availability factor (EAF).
26. Proposals must state the ability of the resource to provide ancillary services (regulation, spinning reserves, non-spinning reserves, load following, black start).
27. Proposals for existing resources must include documentation of all Notice of Violation (NOV) issued by the Idaho Department of Environmental Quality (DEQ) and documentation of corrective action, settlement and penalty.

COUNTERPARTY PROFILE

Respondents must provide information below and answer all questions in the Proposal Entry Form for this RFP. Additionally, Respondents shall provide further supporting documentation as requested by IPC

28. Proposals must provide safety information for the most recent three (3) years including, but not limited to, an annual statement of worker's compensation Experience Modification Rating (EMR), the OSHA Recordable Injury Rates (RIR), and the U.S. Bureau of Labor Statistics (BLS) SIC Code RIR > 1.0, the OSHA citation history, Lost Time Accidents (LTA), number of OSHA-Recordable Cases, and employee hours worked.
29. Respondent must provide an electronic copy of its safety manual. Respondents with safety manuals that have not been updated to meet current OSHA standards within the last twelve (12) months may be disqualified. Respondent must also provide a statement of Respondent's ability to provide an individual that has completed the OSHA thirty (30) hour outreach training course; will be committed and available to support the Services to be performed under the proposal; and will be responsive in a timely manner to IPC's request for participation in safety events, analysis and/or sessions.
30. Proposals must include a list of any citations, notices of violation, legal proceedings, fines, or project terminations that any Federal, State, local regulatory agency or department, corporation, or individual has issued to or against Respondent, or any employee of Respondent while that employee was working for Respondent (Citations). For each Citation, state the nature of the Citation and the date of its resolution, together with the contact person for Respondent who could address any questions about the matter. If there are no Citations, Respondent shall provide such a statement.

31. Respondent must complete and submit the Counterparty Financial Questionnaire and upload a current organizational chart displaying all organizational relationships including parent company, holding company, subsidiaries, sister companies, associates, or other related entities as applicable.
32. Proposals must include a description of Respondent's experience developing resources similar to that proposed. Additional review of Respondent's direct development experience, positive or negative third-party references, and industry reputation may result in the Respondent receiving a higher or lower score than application of the above criteria would otherwise indicate.
33. Proposals must include a general description of the cyber security requirements, practices, and policies of the Respondent. Respondent must state that any and all equipment utilized in the proposed resource will not be procured through an Office of Foreign Assets Control (OFAC) designed entity or otherwise be comprised of equipment prohibited for use by electric utilities in the United States.

COMMUNITY STEWARDSHIP

34. Proposals must state the number of full-time, permanent jobs that will be created in IPC's service territory, details regarding the types of jobs (i.e., roles/functions/titles) and the number of positions for each respectively by year. A full-time, permanent job means 2,080 straight-time paid hours in a fiscal year with benefits.
35. Proposals must provide details and dollar value of permanent capital investment that company intends on making in IPC's service territory (i.e., office lease, warehouse lease, land purchase, etc.) and any timeline associated with these investments.
36. Each proposal must state whether an owner, equity holder, partner, member, or principal of Respondent is a manufacturer, supplier, distributor, or provider (Provider) of technology-related systems, equipment, components, parts, technologies and/or services. If so, the proposal must state the name, address and state of organization of such Provider, describe the nature of the Provider's business, and a description of where the Resource supplies and materials will be sourced from, as well as the percentage, if any, of such sourcing:

    - Outside the USA (provide name and location)
    - In the USA, but outside the State of Idaho and Oregon (provide name and location)
    - In the state of Idaho and Oregon, but outside IPC's service territory
    - Within IPC's service territory (provide name and location)
    - By subcontractors of Respondent, if available
    - A commitment to offer subcontracting opportunities to industry-leading small, local and/or diverse/minority-owned businesses.

37. Respondent must provide information concerning any environmental, social, and governance (ESG) initiatives and any supplier programs, including but not limited to: 1) Risk Rating score it has received from Sustainalytics, an established ESG rating agency, or scores from other ESG rating agencies may be substituted in place of Sustainalytics ratings if they are substantially similar in rating methodology and quality; 2) and any other supplier programs (Small Business And Small Disadvantaged Business Programs, mentoring programs, and academic opportunities).

EXHIBIT B – Information for Quantitative Evaluation

A summary of the information that must be uploaded by the Respondent to the Portal for purposes of the quantitative evaluation is provided below. **This is provided for information only. Respondents are directed to the tabs in the Portal to review all of the information and the specific type and level of detail that must be provided. That level of detail is not provided in this Exhibit. In the case of conflict between this summary and the detail identified in the Portal, the detail identified in the Portal shall govern.**

Storage Technologies

- Battery age (if existing) (cycles)
- Technology
- In Service Date
- Battery life (years)
- Battery life (cycles)
- Number of units
- Age of plant (if existing)
- Technical Life
- Storage Capacity (MWh)
- Battery capacity at peak hour (MW)
- Nameplate Capacity (MW)
- Auxiliary Load (MW)
- Duration (hours)
- Average daily capacity
- Charge efficiency (%)
- Discharge efficiency (%)
- Annual capacity degradation (% of MW per year)
- Capacity degradation per cycle (% of MW per cycle)
- Annual Energy degradation (% of MWh per year)
- Energy degradation per cycle (% of MWh per cycle)
- Minimum state of charge (%)
- Maximum state of charge (%)
- Round trip charging losses (%)
- Maximum number of cycles allowed per day (cycles)
- Maximum number of cycles allowed per month (cycles)
- Maximum number of cycles allowed per week (cycles)
- Maximum number of cycles allowed per year (cycles)
- Maximum time battery can output at maximum generating capacity (hours)
- Maximum generation capacity at IPC peak hours (%)
- Maintenance outages per year (number)
- Forced outage rate (%)
- Mean planned repair time (hours)
- Mean forced repair time (hours)
- Overnight installed cost ($/kW, $/kWh, $)

Wind Technologies

- In Service Date
- Number of units
- Age of plant (if existing)
- Technical Life
- 8760 shape of generation output
- Storage Capacity (MWh)
- Battery capacity at peak hour (MW)
- Nameplate Capacity (MW)
- Auxiliary Load (MW)
- Average daily capacity
- Minimum guaranteed energy level
- Annual capacity degradation (% of MW per year)

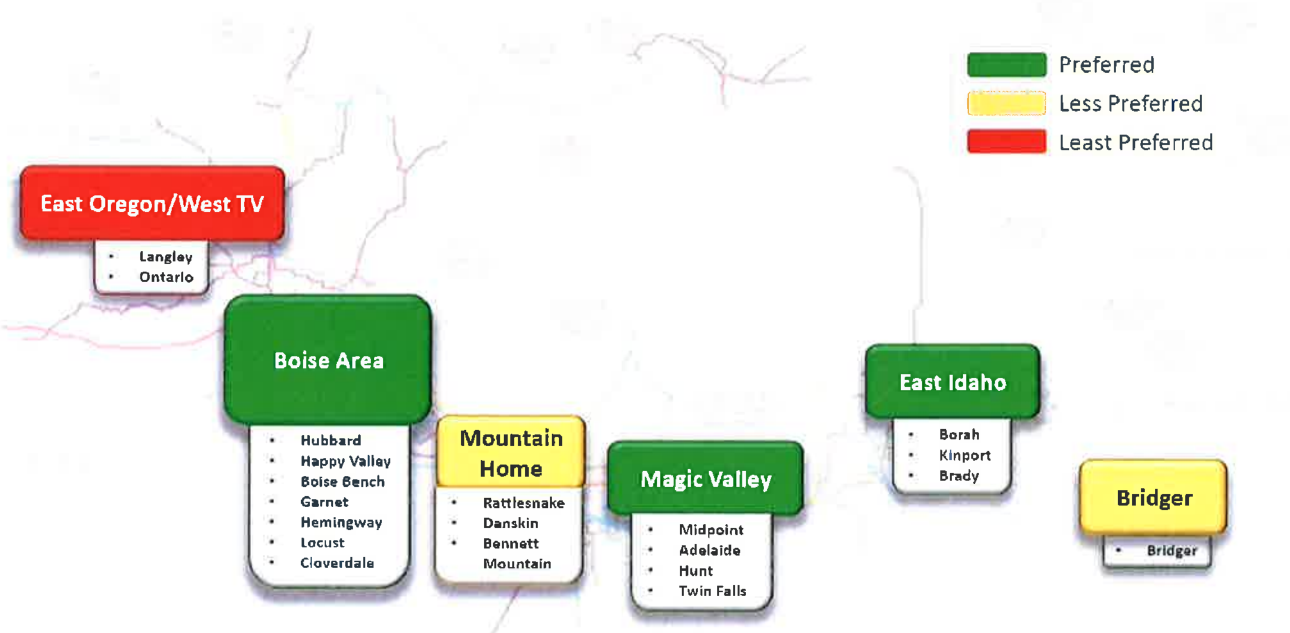
- Maximum time battery can output at maximum generating capacity (hours)
- Maximum generation capacity at IPC peak hours (%)
- Maintenance outages per year (number)
- Forced outage rate (%)
- Mean planned repair time (hours)
- Mean forced repair time (hours)
- Overnight installed cost ($/kW, $/kWh, $)

Solar Technologies

- In Service Date
- Number of units
- Age of plant (if existing)
- Technical Life
- 8760 shape of generation output
- Storage Capacity (MWh)
- Battery capacity at peak hour (MW)
- Nameplate Capacity (MW)
- Auxiliary Load (MW)
- Average daily capacity
- Minimum guaranteed energy level
- Annual capacity degradation (% of MW per year)
- Maximum time battery can output at maximum generating capacity (hours)
- Maximum generation capacity at IPC peak hours (%)
- Maintenance outages per year (number)
- Forced outage rate (%)
- Mean planned repair time (hours)
- Mean forced repair time (hours)
  Overnight installed cost ($/kW, $/kWh, $)

EXHIBIT C – Information on Preferred Locations

The following diagram summarizes the preferred locations and points of delivery for Products proposed in response to this RFP. **This is provided for information only. Respondents are directed to the Portal for the most recent version of this information. In the case of conflict between this information and the information provided in the Portal, the form provided in the Portal shall govern.**



* Substation lists are included for reference; they are not intended to represent a complete list

** Preferred locations based on proximity to load and anticipated interconnection/transmission issues

EXHIBIT D – Information on Most Valuable Hours

The following table illustrates the hours during which capacity and energy are most valuable to IPC for a typical day in each month for the year 2023. Proposals that can help meet 2023 peak capacity needs during critical hours while reducing surpluses off-peak will benefit in IPC's analysis. **This is provided for information only. Respondents are directed to the Portal for the most recent version of this information. In the case of conflict between this information and the information provided in the Portal, the form provided in the Portal shall govern.**

	Summer 2023
Identified Capacity (Deficit) in MW (approximate)	(80)

<u>Most Valuable Hours</u>

	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
January																								
February																								
March																								
April																								
May																								
June																								
July																								
August																								
September																								
October																								
November																								
December																								

= <u>Critical Hours</u>: These are the critical need hours for Idaho Power's capacity deficit

= <u>Valuable Hours</u>: These are in addition to the critical hours; IPC's analysis will favor resources that can meet both the critical hours and the valuable hours

EXHIBIT E – Draft Form Term Sheet

Respondents are directed to the Portal for the Draft Form Term Sheet that must be redlined and uploaded to the Portal.

EXHIBIT F – BESS Technical Specifications

Respondents are directed to the Portal for the BESS Technical Specifications that must be met for a BESS project offered for IPC ownership.

EXHIBIT G – Solar Technical Specifications

Respondents are directed to the Portal for the Solar + Storage Technical Specifications that must be met for a Solar + Storage project offered for IPC ownership.

EXHIBIT H – Wind Technical Specifications

Respondents are directed to the Portal for the Wind Technical Specifications that must be met for a Wind + Storage project offered for IPC ownership.

EXHIBIT I – Mutual Non-Disclosure Agreement

Respondents are directed to the Portal for the draft form Mutual Non-Disclosure Agreement that must be executed prior to discussion of IPC specific cyber security requirements.

EXHIBIT J - Counterparty Financial Questionnaire

Respondents are directed to the Portal for the Counterparty Financial Questionnaire document for which a response must be included in any proposal.

EXHIBIT K – Draft Form Letter of Credit

Respondents are directed to the Portal for the Draft Form Letter of Credit that must be redlined and submitted as part of a proposal

End of Document

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-21-41

IDAHO POWER COMPANY

ATTACHMENT 3

The Timeline and Events of the February 2021 Texas Electric Grid Blackouts

July 2021

The University of Texas at Austin
Energy Institute

The Timeline and Events of the February 2021 Texas Electric Grid Blackouts

A report by a committee of faculty and staff at The University of Texas at Austin

July 2021

COMMITTEE CHAIRS

Carey W. King, *Research Scientist, Assistant Director, Energy Institute*
Josh D. Rhodes, *Research Associate, Department of Mechanical Engineering*
Jay Zarnikau, *Research Fellow, Department of Economics*

COMMITTEE MEMBERS

Contributing Authors
Ning Lin, *Chief Economist, Bureau of Economic Geology*

Additional Members
Erhan Kutanoglu, *Associate Professor, Operations Research and Industrial Engineering, Department of Mechanical Engineering*
Benjamin Leibowicz, *Assistant Professor, Operations Research and Industrial Engineering, Department of Mechanical Engineering*
Dev Niyogi, *Professor, Department of Geological Sciences; Professor, Department of Civil, Architectural, and Environmental Engineering*
Varun Rai, *Professor, LBJ School of Public Affairs; Director, Energy Institute*
Surya Santoso, *Professor, Department of Electrical and Computer Engineering*
David Spence, *Baker Botts Chair in Law, School of Law; Professor, Department of Business, Government, and Society*
Stathis Tompaidis, *Professor, Department of Information, Risk and Operations Management, and by courtesy, Department of Finance*
Hao Zhu, *Assistant Professor, Department of Electrical and Computer Engineering*

OTHER CONTRIBUTORS

Erik Funkhouser, *Director for Research Coordination and Partnerships, Energy Institute*
Brent Austgen, *Graduate Research Assistant, Operations Research and Industrial Engineering Program, Department of Mechanical Engineering*

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Executive Summary

Objective

This report recounts the factors contributing to disruptions in electricity and natural gas service in Texas during Winter Storm Uri, with a particular focus on blackouts on the Electric Reliability Council of Texas (ERCOT) grid during the period from February 15-18, 2021. Our goal is to create a common basis of fact to educate the debate over strategies to avoid similar problems in the future. We specifically limited the scope of this report to the events during February 2021, a comparison of the February 2021 event to the previous energy system disruptions in 1989 and 2011 during winter storms, and the economic consequences of the event in February 2021. An appendix describes the long-term evolution of the ERCOT electricity market and provides historical context.

This report is not intended to comprehensively address all issues stemming from such a complex event, but may inform subsequent assessments. This report does not recommend policies or solutions.

Data

To perform the analysis presented in this report, we reviewed a variety of public information sources, analyses conducted by the staff of ERCOT, testimony before state legislative committees, and public data archives provided by ERCOT. In addition, and through an agreement with the Public Utility Commission of Texas (PUCT), select members of our project team were provided access to certain confidential data collected by the PUCT and ERCOT pertaining to the performance of specific electric generating units, enrollment of energy consumers in ERCOT's Emergency Response Service program, communications regarding the winter storm, and other relevant information.[1] We also used a proprietary source of data to explore the performance of the natural gas industry during the event. We further considered and analyzed meteorological and other technical data that groups within the University of Texas at Austin (UT) have acquired for other research purposes.

Findings

The failure of the electricity and natural gas systems serving Texas before and during Winter Storm Uri in February 2021 had no single cause. While the 2021 storm did not set records for the lowest recorded temperatures in many parts of the state, it caused generation outages and a loss of electricity service to Texas customers several times more severe than winter events leading to electric service disruptions in December 1989 and February 2011. The 2021 event exceeded prior events with respect to both the number and capacity of generation unit outages, the maximum

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[1] Josh Rhodes and Carey King of the project team were provided access to the confidential data.

load shed (power demand reduction) and number of customers affected, the lowest experienced grid frequency (indicating a high level of grid instability), the amount of natural gas generation experiencing fuel shortages, and the duration of electric grid operations under emergency conditions associated with load shed and blackout for customers. The financial ramifications of the 2021 event are in the billions of dollars, likely orders of magnitude larger than the financial impacts of the 1989 and 2011 blackouts.

Factors contributing to the electricity blackouts of February 15-18, 2021 include the following:

- *All types of generation technologies failed*. All types of power plants were impacted by the winter storm. Certain power plants within each category of technologies (natural gas-fired power plants, coal power plants, nuclear reactors, wind generation, and solar generation facilities) failed to operate at their expected electricity generation output levels.
- *Demand forecasts for severe winter storms were too low.* ERCOT's most extreme winter scenario underestimated demand relative to what actually happened by about 9,600 MW, about 14%.
- *Weather forecasts failed to appreciate the severity of the storm.* Weather models were unable to accurately forecast the timing (within one to two days) and severity of extreme cold weather, including that from a polar vortex.
- *Planned generator outages were high, but not much higher than assumed in planning scenarios.* Total planned outage capacity was about 4,930 MW, or about 900 MW higher than in ERCOT's "Forecasted Season Peak Load" scenario.
- *Grid conditions deteriorated rapidly early in February 15 leading to blackouts.* So much power plant capacity was lost relative to the record electricity demand that ERCOT was forced to shed load to avoid a catastrophic failure. From noon on February 14 to noon on February 15, the amount of offline wind capacity increased from 14,600 MW to 18,300 MW (+3,700 MW).[2] Offline natural gas capacity increased from 12,000 MW to 25,000 MW (+13,000 MW). Offline coal capacity increased from 1,500 MW to 4,500 MW (+3,000 MW). Offline nuclear capacity increased from 0 MW to 1,300 MW, and offline solar capacity increased from 500 MW to 1100 MW (+600 MW), for a total loss of 24,600 MW in a single 24-hour period.

[2] For wind and solar electricity generation, nameplate capacity is not a meaningful measure of the amount of power generation expected when the unit is not experencing an outage, though nameplate capacity provides a meaningful metric for the thermal fleet of power plants (e.g., coal, nuclear, and natural gas-fired generating units). Using backcasted values of the available wind and solar radiation, available wind capacity outages actually decreased from 9,070 MW to 5,020 MW (-4,050) over the same time period and solar outages increased less, from 108 MW to 545 MW (+437 MW).

- *Power plants listed a wide variety of reasons for going offline throughout the event.* [3] Reasons for power plant failures include "weather-related" issues (30,000 MW, ~167 units), "equipment issues" (5,600 MW, 146 units), "fuel limitations" (6,700 MW, 131 units), "transmission and substation outages" (1,900 MW, 18 units), and "frequency issues" (1,800 MW, 8 units). [4]
- *Some power generators were inadequately weatherized; they reported a level of winter preparedness that turned out to be inadequate to the actual conditions experienced.* The outage, or derating, of several power plants occurred at temperatures above their stated minimum temperature ratings.
- *Failures within the natural gas system exacerbated electricity problems.* Natural gas production, storage, and distribution facilities failed to provide the full amount of fuel demanded by natural gas power plants. Failures included direct freezing of natural gas equipment and failing to inform their electric utilities of critical electrically-driven components. Dry gas production dropped 85% from early February to February 16, with up to 2/3 of processing plants in the Permian Basin experiencing an outage.[5]
- *Failures within the natural gas system began prior to electrical outages.* Days before ERCOT called for blackouts, natural gas was already being curtailed to some natural gas consumers, including power plants.
- *Some critical natural gas infrastructure was enrolled in ERCOT's emergency response program.* Data from market participants indicates that 67 locations (meters) were in both the generator fuel supply chain and enrolled in ERCOT's voluntary Emergency Response Service program (ERS), which would have cut power to them when those programs were called upon on February 15. At least five locations that later identified themselves to the electric utility as critical natural gas infrastructure were enrolled in the ERS program.
- *Natural gas in storage was limited.* Underground natural gas storage facilities were operating at maximum withdrawal rates and reached unprecedently-low levels of working gas, indicating that the storage system was pushed to its maximum capability.

The ERCOT system operator managed to avoid a catastrophic failure of the electric grid despite the loss of almost half of its generation capacity, including some black start units that would have been needed to jump-start the grid had it gone into a complete collapse.

[3] Some power plants experienced multiple outages and may be included in more than one category.

[4] The maximum values during the event are presented here for both capacity and numbers of units. Different categories may have experienced peak outage rates at different times.

[5] Based on our data sample of 27 natural gas processing plants.

Had one or more of the problems listed above not occurred, outages might still have occurred, but their duration and severity would likely have been lower. The magnitude of the failures caused unprecedented impacts:

- Rolling blackouts turned into persistent days-long electrical outages affecting millions of Texans connected to the ERCOT grid and leading to loss of life.
- The financial impacts were tremendous. According to PUCT data, natural gas prices, normally much less than $10/MMBTU, spiked to over $400/MMBTU at Texas trading hubs. Natural gas providers that were able to produce and transport gas reported windfall profits. Many financial sector firms that operate in the ERCOT energy market also reported large profits.
- The price of electricity spiked to $9,000 per MWh and stayed there by orders of the PUCT, which suspended some market price setting rules during the electricity blackouts. The PUCT stated that high prices were intended to ensure that generating units would participate in the market and that price-sensitive energy consumers would minimize their demand for electricity from the market. The PUCT also stated that the suspension of the rules was due to two reasons. First, to account for load that had been removed due to forced outages from the calculation of prices. Second, to avoid potentially even higher electricity prices that would result from the high price of natural gas.[6]
- The financial losers included power generators whose equipment failed, generators dependent upon natural gas that were unable to obtain the fuel or were unhedged to high natural gas prices, and load serving-entities (retail electric providers, municipal utility systems, and rural electric cooperatives) who were inadequately hedged.
- Many market participants defaulted on their payment obligations to ERCOT, which serves as a central counter-party in the markets for electrical energy and ancillary services that it administers. These defaults may translate into increased costs for electricity consumers in Texas for many years to come.

Disclaimers

This report was funded in part by the PUCT via an Interagency Agreement with the University of Texas at Austin (UT). Beyond funding, the Interagency Agreement between the PUCT and UT provided certain members of the research team, under a confidentiality agreement, with access to electricity market participant data and other confidential information collected by the PUCT and ERCOT. The PUCT reviewed a draft of this report to ensure that no confidential information was inadvertently disclosed. The committee had full discretion as to the content and presentation of material in the report.

[6] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

Any opinions or positions expressed in this report are those of the authors alone and do not reflect any official positions of the PUCT, ERCOT, the University of Texas at Austin, or the Board of Regents of the University of Texas.

1. Introduction

1.1 Objective

This report recounts the factors contributing to the disruptions in electricity and natural gas service in Texas during Winter Storm Uri, with a particular focus on the outages in electrical service in the Electric Reliability Council of Texas (ERCOT) power region during the period from February 15-18, 2021. In pursuing this report's objective, the Energy Institute at the University of Texas at Austin assembled a team of faculty and researchers to identify and review credible sources of data in an attempt to provide a factual account of what happened and what went wrong during the winter storm.

Our goal is not to provide recommendations, but to create a common basis of fact to educate the debate over policy changes under consideration as a response to the winter storm. We specifically limited the scope of this report to the events and economic impacts of February 2021, including a comparison to previous winter storm blackouts of 1989 and 2011. To provide additional historical context, we include an appendix that describes the long-term evolution of the ERCOT electricity market. This report is not intended to comprehensively address all issues stemming from such a complex event, but can inform future assessments.[7]

This report was funded in part by the Public Utility Commission of Texas (PUCT). Beyond funding, the Interagency Agreement between the PUCT and the University of Texas at Austin (UT) provided the research team with access to confidential electricity market information under a confidentiality agreement. The PUCT reviewed a draft of this report to ensure that no confidential information was inadvertently disclosed, but any views expressed are solely those of the authors and supporting committee members. The authors had full discretion as to the content and presentation of material in the report.

Various participants in the state's natural gas and electricity markets fund research at UT, and some contributors to this report have performed such funded research or provide consulting assistance to companies or organizations involved in the energy industry. Disclosures of any relationships that might be perceived to introduce a conflict of interest are available via the UT Energy Institute and at: https://energy.utexas.edu/ercot-blackout-2021.

[7] Other reports might include a more-comprehensive or focused analyses that might later be developed by the Federal Energy Regulatory Commissions (FERC), the North American Electric Reliability Corporation (NERC), the PUCT, or other government bodies.

1.2. Energy in Texas

Texas is the nation's leading state in electricity and natural gas in both production and consumption. Electricity is provided to the majority of the state's consumers through an intra-state grid, managed by ERCOT as an independent system operator, with limited interconnection to the other two main electrical grids serving the U.S. and Canada, as noted in Figure 1.a. Limited federal regulatory jurisdiction within the ERCOT power region has permitted the development of a unique electricity system involving competition among generators of electricity in the wholesale sector and "customer choice" or retail competition in some areas of the state which were served by vertically-integrated investor-owned utilities prior to 2001.

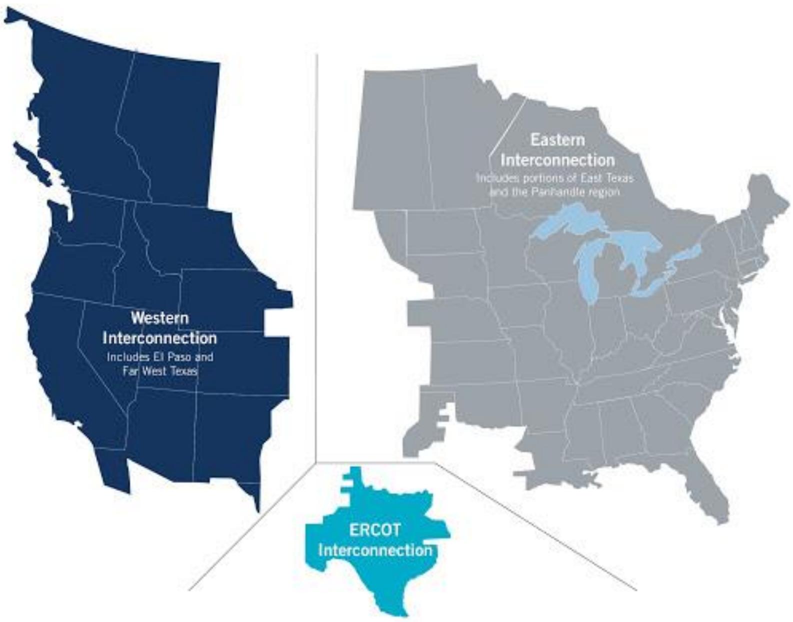

Figure 1.a. ERCOT in relation to the other two grid interconnections in the U.S. and Canada.[8]

Natural gas has long been the leading fuel for the generation of electricity in Texas, although the state has become a leader in the generation of electricity from renewable energy sources in recent years. Despite the interdependence of the state's natural gas and electricity industries, different state agencies have regulatory oversight over the two industries. While the PUCT oversees electricity services (and has regulatory oversight over certain aspects of water and telecommunications services), the natural gas sector is regulated by Texas Railroad Commission (RRC). The PUCT's oversight over the electricity industry includes responsibility for overseeing the operations of the electric grid operator, ERCOT. Appendix A provides

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[8] ERCOT: http://www.ercot.com/news/mediakit/maps,
http://www.ercot.com/content/wcm/landing_pages/89373/ERCOT-Internconnection_Branded.jpg

additional information and historical context pertaining to the development and operation of ERCOT.

The following Chapter 2 reviews the physical aspects of the February 2021 event, examining conditions of the electricity and natural gas industries in the days prior and during the winter storm. Both the demand and supply sides of energy markets are discussed. Chapter 3 examines prices in electricity and natural gas markets, and the impact of the price spikes upon market participants in these industries. Chapter 4 contrasts the February 2021 event to previous winter events in 1989 and 2011 that prompted electrical outages. Chapter 5 provides a brief summary of this report.

2. Timeline of Events Related to February 2021 ERCOT Blackouts

We begin this chapter by recounting the electricity generating capacity anticipated in advance of the event, as suggested by winter resource adequacy analyses conducted by the ERCOT staff and updated information available to the market in the days prior to the event. Electric load forecasts and their underlying weather forecasts and assumptions are reviewed. Operational activities on the electric side are then discussed, including efforts by the grid operator, transmission and distribution providers, and others to constrain the demand for electricity. We conclude this chapter with a focus on natural gas operations before and during the event.

2.1. ERCOT's Winter 2020/2021 SARA report

ERCOT develops a Seasonal Assessment of Resource Adequacy (SARA)[9] report for each of the fall, winter, spring, and summer seasons that "focuses on the availability of sufficient operating reserves to avoid emergency actions such as the deployment of voluntary load reduction resources." Each SARA report is released one to two months before the season under study. In a SARA report, ERCOT assumes a set of hours at which the peak electricity demand will occur. For the winter, ERCOT assumes peak demand will occur between 7 am and 10 am. The winter 2020/2021 SARA report,[10] released on November 5, 2020, indicated that ERCOT's "Forecasted Season Peak Load" scenario expected that about 74,000 MW of net resource capacity[11] would be available to meet a winter peak of 57,699 MW. This includes an assumed *"… unit outage forecast of 8,616 MW during the winter months, which is based on historical winter outage data compiled since 2017*" (Figure 2.a). A quantity of Positive Reserves[12] (far right, green bar of Figure 2.a) above a few thousand megawatts indicates that, under this scenario, the chance of load shed (blackouts) was low. The report also noted that the previous (to 2021) all-time winter peak was 65,915 MW and occurred on January 17, 2018.

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[9] See: http://www.ercot.com/gridinfo/resource.

[10] SARA-FinalWinter2020-2021: http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.xlsx

[11] Total Resources – Maintenance Outages – Forced Outages (82,513 MW – 4074 MW – 4542 MW = ~74,000 MW)

[12] Positive reserves refers to "Capacity Available for Operating Reserves."

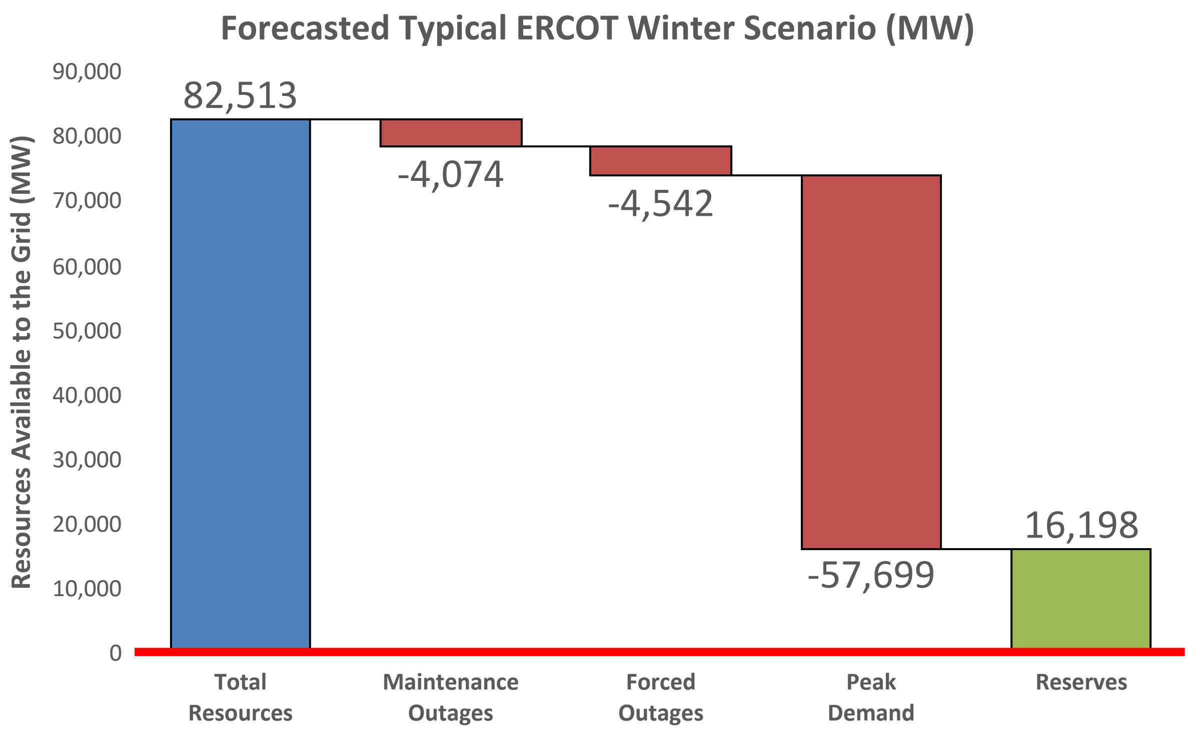

Figure 2.a. Waterfall chart of the ERCOT "Forecasted Season Peak Load" Winter 2020/2021 SARA scenario showing the total amount of Resources assumed for ERCOT as well as expected plant outages and peak demand. This scenario indicated that ERCOT would have over 16,000 MW of reserves, sufficient capacity to match supply and demand.

ERCOT's Winter 2020/2021 SARA scenario indicated the scenario that resulted in the least amount of reserve capacity was the "Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load" scenario (Figure 2.b). This scenario assumed 67,208 MW load and 13,953 MW of thermal power plant outages, such that there would be only 1,352 MW of operating reserves. This level of reserves is below 2,300 MW, a level that ERCOT indicates is at risk of Energy Emergency Alert actions.[13] This "extreme" scenario did not assume any downward adjustments for low wind output, but ERCOT's "Extreme Low Wind Output" SARA scenario does assume a downward adjustment of 5,279 MW.

[13] http://www.ercot.com/content/wcm/lists/164134/EEA_OnePager_FINAL.PDF

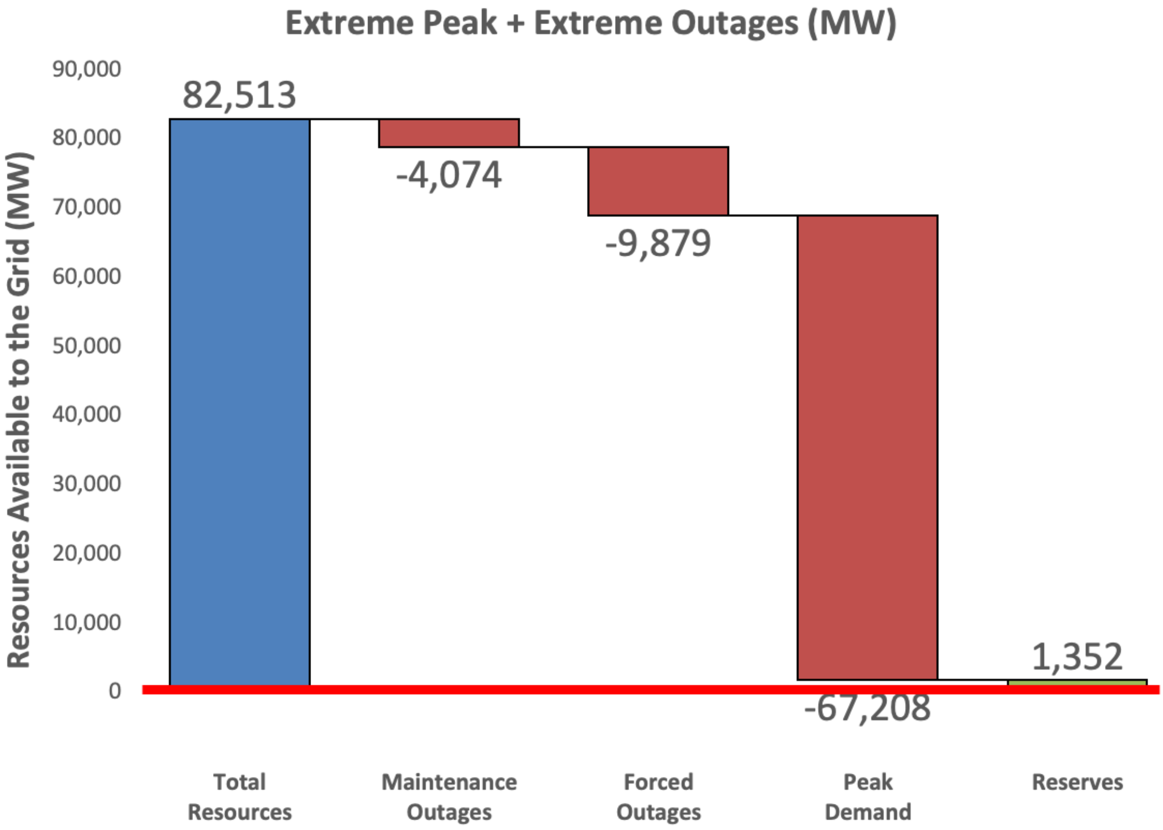

Figure 2.b. Waterfall chart of the ERCOT "Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load" Winter 2020/2021 SARA scenario. This scenario indicated that ERCOT would have only 1,352 MW of reserves, insufficient capacity to prevent an Energy Emergency Alert.

Figure 2.c shows the shortfall of generation during the hour of the week of February 14, 2021 with the highest deficit in reserves. There were over 26,200 MW of forced thermal (i.e., natural gas, coal, nuclear, biomass) power plant outages, over 2.5 times the assumed worst case in any SARA report scenario.

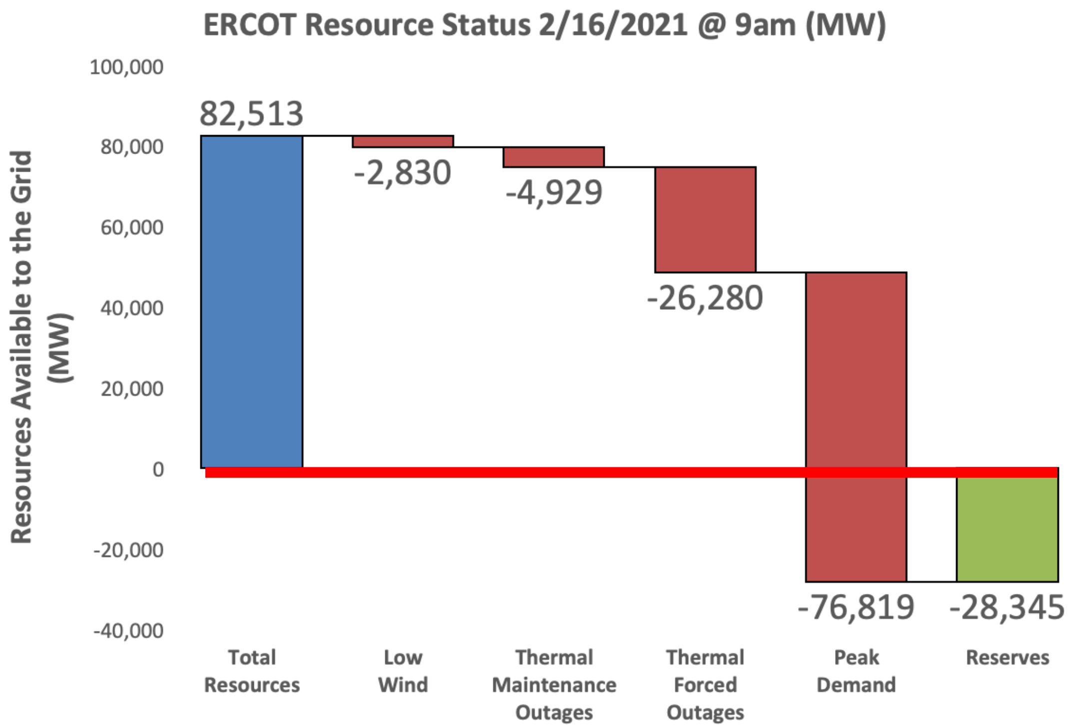

Figure 2.c. Waterfall chart of the actual resource availability at the time of peak demand (February 16, 2021 at 9 am) indicating a shortage of 28,345 MW in capacity due to lower than forecasted wind output, a higher capacity offline for maintenance, and over 26,000 MW of capacity triggered offline as instigated by the weather conditions.[14]

2.2. The Week Before Winter Storm Uri

2.2.1. Weather and Load Forecasts and Alerts

At the end of January, internal discussions between ERCOT's meteorologist and various planning groups began about a potential February cold weather event.[15] However, it wasn't until February 8 that the weather models used by the ERCOT staff began to show a worrisome event for the ERCOT service region. There is inherent uncertainty in the ability of weather models to forecast the timing and severity of extreme cold weather events, such as a polar vortex – even when it is known to be present in North America. As late as February 13, weather models used by ERCOT still disagreed on forecasted morning cold temperatures in Texas cities by as much as 10°F.

The discussion from the National Weather Service Houston/Galveston office provides a summary of the widespread nature of the winter storm.[16] The meteorological events unfolded as follows: A cold front moved in February 10, followed by a winter

[14] The terms "Low Wind," "Thermal Maintenance Outages," and "Thermal Forced Outage" relate to those used in the Winter 2020/2021 ERCOT SARA report.

[15] We summarize these internal ERCOT weather-related communications in the Appendix.

[16] Available at https://www.weather.gov/hgx/2021ValentineStorm

weather advisory (WWA) on February 11, followed by a Winter Storm Watch (WSW) on February 12. From February 13 in the night through February 14, the weather worsened further and the entire state was under a WSW and a Hard Freeze Warning.

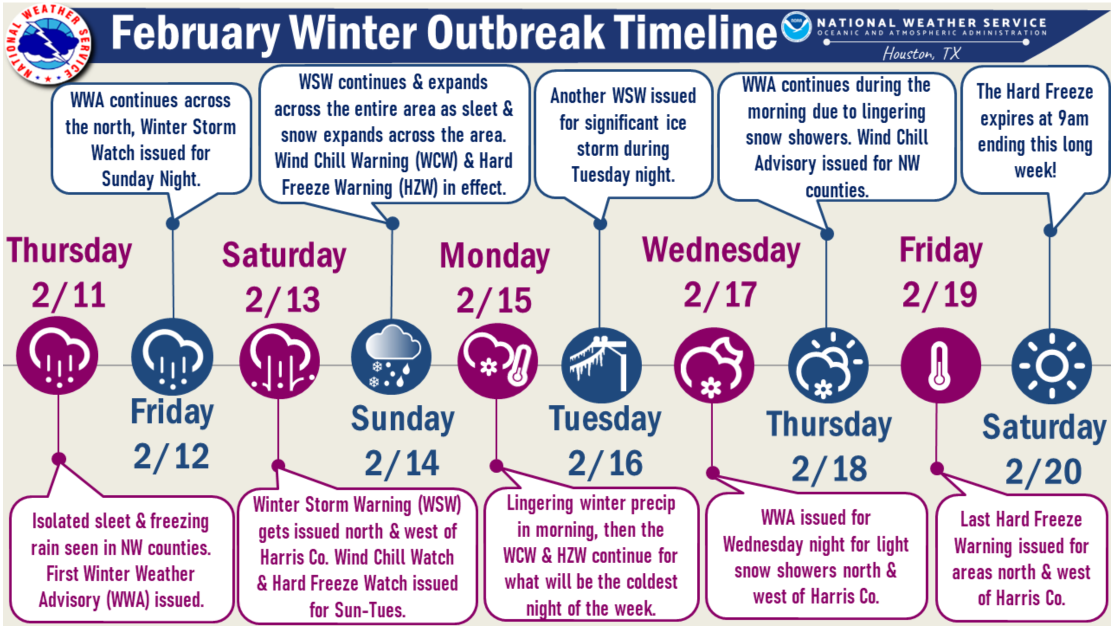

Figure 2.d. Timeline of weather conditions during event

The cold weather experienced was a result of a polar vortex that was impacting temperatures across the U.S. The Dallas/Ft. Worth National Weather Service reported:

> The record cold spell and extended period of wintry weather was caused by the upper-level polar vortex dropping south from the north pole and then lingering over South Central Canada for more than a week. This allowed cold arctic air to gradually spill southward into Texas. At the same time, several upper-level disturbances riding the jet stream moved through the area providing lift and moisture for winter precipitation. These disturbances show up as waves or dips in the lines that move in from the west. Ahead of each wave, upper-level lift increases and moisture is drawn up from the south. Since it was already so cold, this precipitation fell as snow, sleet, and freezing rain.[17]

Since the event was due to an evolving vortex situation, the meteorological community could provide warnings related to unusually cold temperatures towards the end of January. For example, on February 3, CNN's headline was "Every US State

[17] https://www.weather.gov/fwd/Feb-2021-WinterEvent.

will see below freezing temperatures over the next week," and mentioned "It's about to get so cold that boiling water will flash freeze, frostbite could occur within 30 minutes and it will become a shock to the system for even those who are used to the toughest winters."[18]

This nature of advance warning (from 7 to 14 days ahead of the event) is unusual. However, the southward migration of the polar vortex was being monitored and predicted by different weather forecast modeling systems in early January. The Washington Post had a report on January 5 titled "The polar vortex is splitting in two, which may lead to weeks of wild winter weather."[19]

In hindsight, while it is apparent that concerns regarding unusually cold winter events were flashing, it is important to note that the system inherently is difficult to predict. The same article highlights that: "The United States is slightly more of a winter wild card for now, experts say, with individual winter storms tough to predict beyond a few days in advance."

ERCOT's first Operating Conditions Notice[20] mentioning the approaching winter storm was on February 8, 2021 – a week before the first of the blackouts began. The notice asked generators to update their ability to provide power and review fuel supplies:

> At 18:53 [February 8, 2021], ERCOT is issuing an OCN for an extreme cold weather system approaching Thursday, February 11, 2021 through Monday, February 15, 2021 with temperatures anticipated to remain 32°F or below. QSEs are instructed to: Update COPs and HSLs when conditions change as soon [as] practicable, Review fuel supplies, prepare to preserve fuel to best serve peak load, and notify ERCOT of any known or anticipated fuel restrictions, Review Planned Resource outages and consider delaying maintenance or returning from outage early, Review and implement winterization procedures. Notify ERCOT of any changes or conditions that could affect system reliability.[21]

ERCOT subsequently issued both an extreme cold weather event advisory and a watch on February 10 and 11, respectively. On February 12, the Texas Governor declared a state of emergency due to the severity of the winter storm.[22]

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[18] https://www.cnn.com/2021/02/02/weather/polar-vortex-forecast-freezing-cold/index.html

[19] https://www.washingtonpost.com/weather/2021/01/05/polar-vortex-split-cold-snow/

[20] http://www.ercot.com/services/comm/mkt_notices/opsmessages/2021/02

[21] See ERCOT glossary: http://www.ercot.com/glossary. QSE: Qualified Scheduling Entity. COP: Current Operating Plan. HSL: High Sustainable Limit. OCN: Operating Condition Notice

[22] https://gov.texas.gov/uploads/files/press/DISASTER_severe_weather_FINAL_02-12-2021.pdf

On February 10th, as cold temperatures entered the ERCOT region, the total amount of offline power plant capacity increased from 14,400 MW to 25,850 MW, or about 12% to 21% of the total 123,050 MW of installed nameplate capacity in ERCOT. The term nameplate capacity refers to the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.[23] Nameplate capacity is different than the power output one expects from any given generation unit on average or at any given time when it operates in concert with all generation units in an electric grid.

Wind turbines suffered some of the earliest outages and derates as freezing precipitation and fog resulted in ice accumulation on blades and – eventually, as temperatures dropped further – in the gearboxes and nacelles. Unit-specific data indicate that other types of generators – mostly those fueled with natural gas – were facing pre-blackout fuel supply issues, and were starting to go offline or derate capacity as early as February 10 due to fuel delivery curtailments.

Because load projections are based on weather forecasts, uncertainty about the weather meant that ERCOT's load forecasts did not fully anticipate the spike in electricity demand that would result from the winter storm. As the winter event drew closer and its magnitude became clearer, forecast accuracy improved considerably.[24]

Figure 2.e depicts the hourly forecasts released to the market on February 8, 10, 12, and 14 for the ensuing seven days. For example, the forecast released at 8:30 a.m. on February 8 projected total system demand of 58,728 MW for 8 a.m. on February 15. ERCOT estimated that the actual demand would have been 75,573 MW had there been no load shed during that hour.[25] The forecast released on February 14 was considerably more accurate, though it remained 3,540 MW too low.

Figure 2.f shows the forecast error using ERCOT's estimate of the load had there been no load shed minus the forecasts released to the market at 8:30 a.m. on February 11, 12, 13, and 14 – a measure of how well ERCOT's load forecasts predicted the coming demand on the system. Forecasted electrical demands for the late night/early morning hours were the least accurate.

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[23] Energy Information Adminstration glossary definition of nameplate capacity: https://www.eia.gov/tools/glossary/index.php?id=G#gen_nameplate.

[24] Recent load forecasts are available at: www.ercot.com/gridinfo. An archive of past load forecasts was provided by ERCOT for the purpose of this analysis.

[25] http://www.ercot.com/content/wcm/lists/227689/Available_Generation_and_Estimated_Load_without_Load_Shed_Data.xlsx

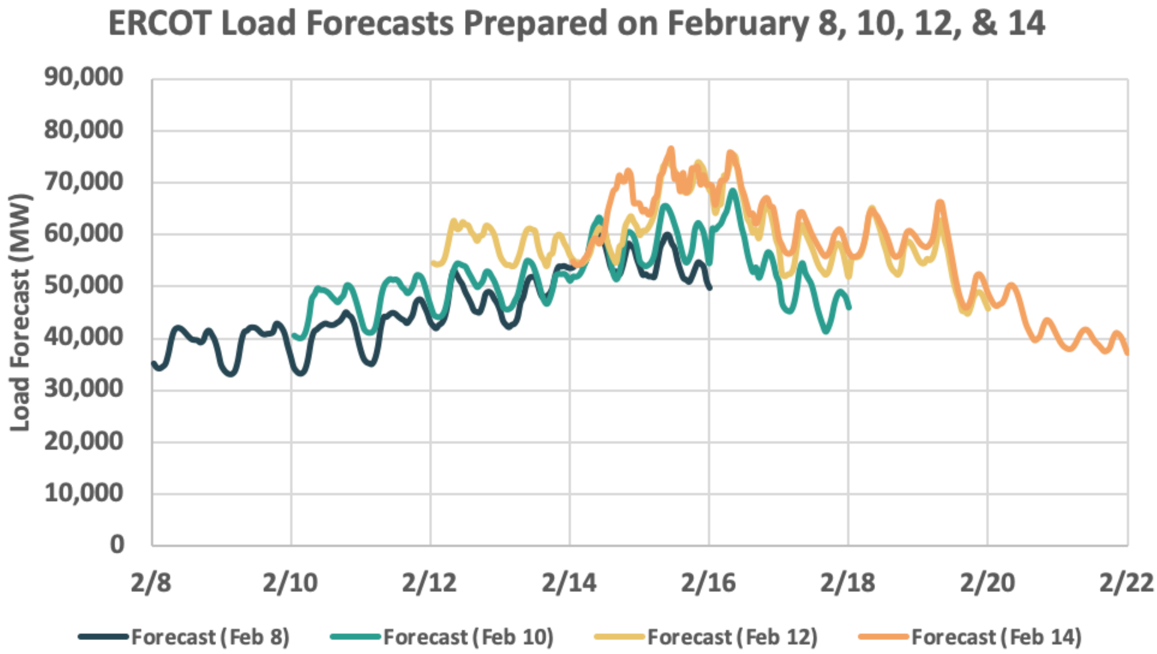

Figure 2.e. ERCOT 7-day (hourly resolution) load forecasts for February 8, 10, 12, and 14.

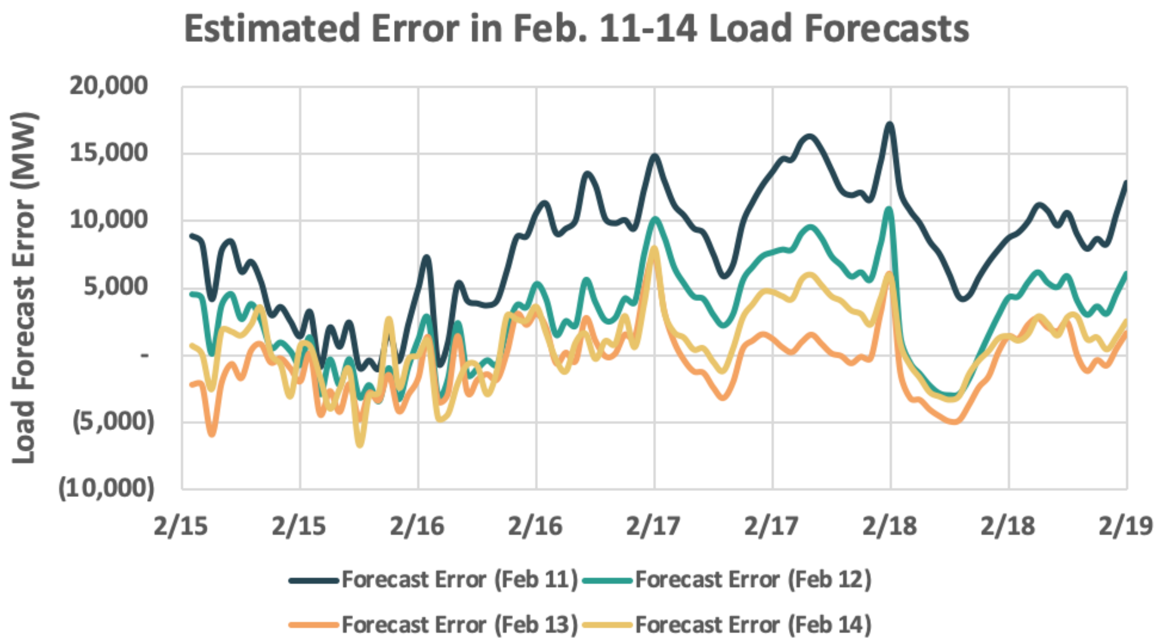

Figure 2.f. The error in ERCOT 7-day (hourly resolution) load forecasts made on February 11, 12, 13, and 14 compared to actual demand on the days of February 15-18, 2021.26

[26] Positive values represent the errors (in MW) of forecasts that were lower than actual demand.

The load forecasting error can be at least partially explained by errors in the weather forecasts upon which the electricity demand forecasts were based. Figure 2.g and Figure 2.h depict hourly temperature forecasts, for two of eight ERCOT weather zones, upon which the demand projections in Figure 2.e were presumably based.[27] The North Central zone includes Dallas and Fort Worth, while the South Central zone includes San Antonio and Austin.[28]

The forecast available to ERCOT on February 8 anticipated a low in North Central Texas of 20.5^{o}F at 4:00 a.m. on February 14, for the entire week of the winter event. The February 12 forecast was updated, and it was expected that the region would experience a low 20 degrees colder at just 0.5^{o}F at 6:00 a.m. on February 16.

The data for South Central Texas show a similar pattern. The February 8 forecast showed a low of 26^{o}F at 4:00 a.m. on February 14, for the entire week of the winter event. By February 12, a low of 9^{o}F was expected in the region at 5:00 a.m. on February 16.

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[27] Temperature data are available in the Market Information page on www.ercot.com. An archive of the "Weather Assumptions" file was obtained from ERCOT for this analysis.

[28] Note that ERCOT uses data from 29 weather stations. Each zone includes two or three weather stations. Thus, the temperature data discussed here do not correspond with a single weather station.

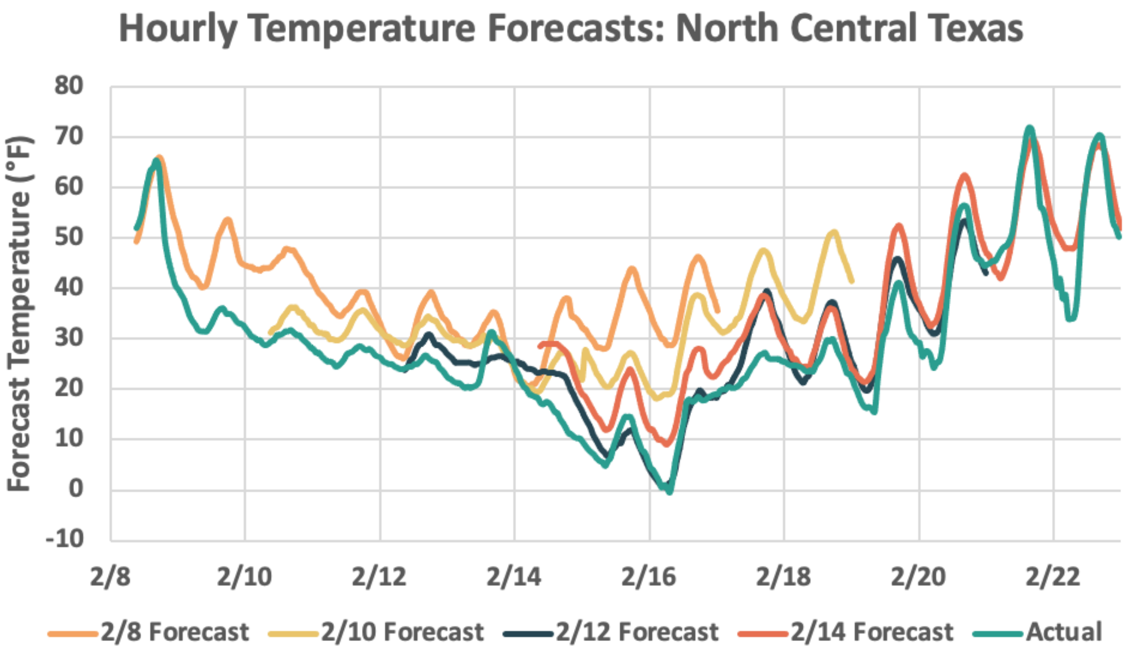

Figure 2.g. Temperature forecasts, as used by ERCOT, for the North Central Texas load region as of the mornings of February 8, 10, 12, and 14. Also shown are the ERCOT staff's calculations of the actual temperatures in the region.

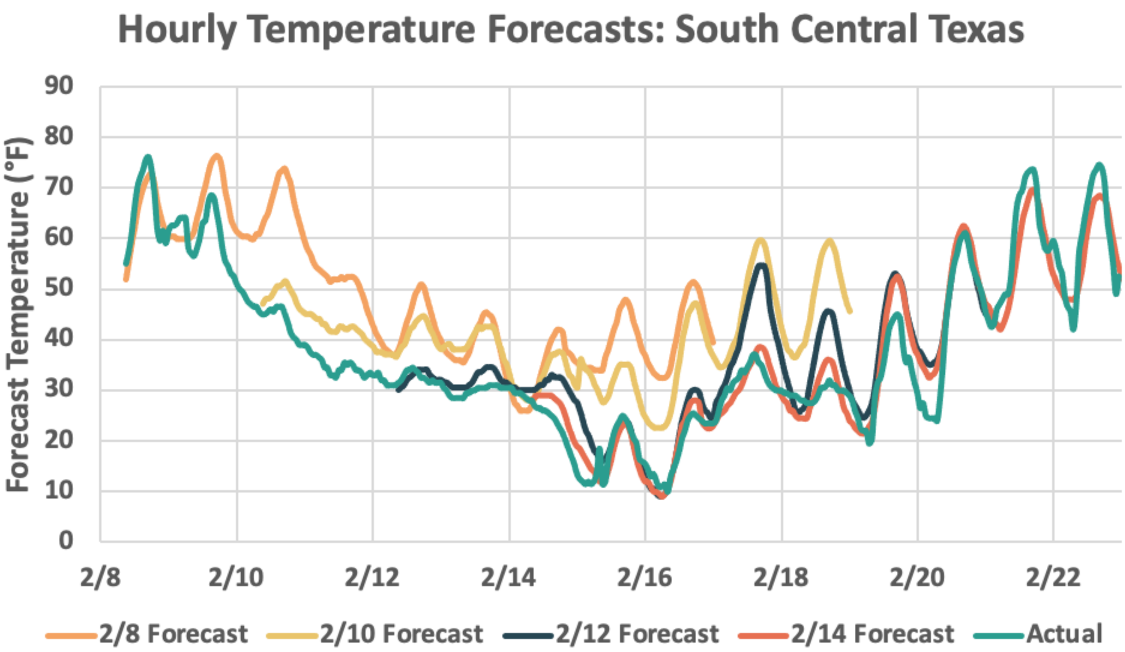

Figure 2.h. Temperature forecasts, as used by ERCOT, for the South-Central Texas load region as of the mornings of February 8, 10, 12, and 14 along with actual temperatures. Also shown are the ERCOT staff's calculations of the actual temperatures in the region.

2.2.2. Recall of Power Plant Outages for Maintenance

At the time (February 8) of ERCOT's first Operating Condition Notice, approximately 6,630 MW of thermal generation were offline for planned maintenance, corresponding to 2,550 MW above the level assumed in SARA scenario "Forecasted Season Peak Load." By the end of Sunday, February 14, about 1,700 MW of generation had been brought back online from either finished or cancelled maintenance, bringing the total planned outage value to 4,930 MW, about 900 MW higher than in the "Forecasted Season Peak Load" SARA scenario (Figure 2.a).

2.3. The Week of Winter Storm Uri (February 13-20, 2021)

On Saturday, February 13 ERCOT began to deploy Responsive Reserves[29] and issued an Emergency Notice for the extreme cold weather event impacting the region. February 13 was also the first day that large generators began to unexpectedly go offline. On Sunday, February 14, ERCOT issued a public appeal for energy conservation and issued multiple watches regarding power supply shortages (Figure 2.i).

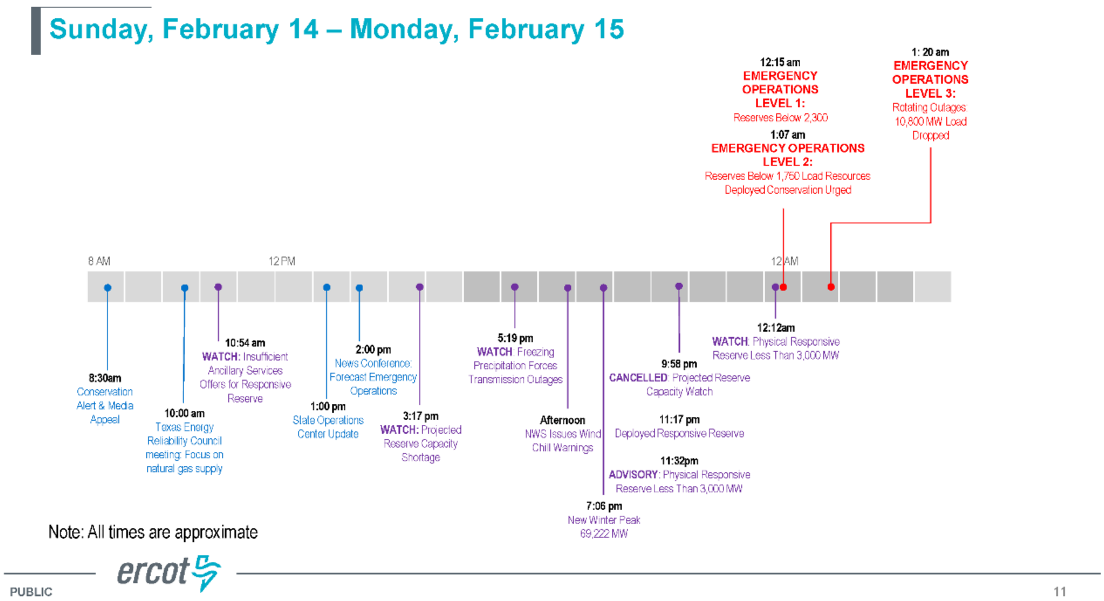

Figure 2.i. ERCOT communications and triggers of Energy Emergency Alerts in the hours leading up to the major load shedding events of the night of February 14 and early morning of February 15, 2021 (ERCOT, 2021).

During the late hours of February 14, electricity load, or demand, was approaching available generation. As generation could not sufficiently increase to meet demand,

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[29] Responsive Reserves are an Ancillary Service that provides operating reserves that is intended to: 1) arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using Primary Frequency Response and interruptible Load; 2) after the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal; 3) provide energy or continued interruption of load during the implementation of the EEA; and 4) provide backup regulation.

the frequency of the grid began to decline.[30,31] In such circumstances, ERCOT begins various contingency plans such as calling on reserves and shedding load, and at low enough frequencies, automated load shed can occur.[32,33]

On Monday, February 15 at 00:15 CST, ERCOT declared an Energy Emergency Alert Level 1 (EEA 1), at 01:07 CST ERCOT moved to EEA 2,[34] and at 01:20 CST, ERCOT declared an EEA 3 event and began "firm load shed" or "blackouts."[35] ERCOT did not return to normal operations until 10:36 CST Friday, February 19. The ERCOT system frequency reached a low of 59.302 Hz at roughly 1:55am on February 15, 2021.

It is important to note that ERCOT protocols allow generators to automatically "trip" offline, or automatically shut down and disconnect from the grid, if the grid frequency drops to 59.4 Hz or below for more than 9 minutes (Table 2.a). This automatic shutdown lowers the risk of exposure to harmful vibrations and heat that can damage generation equipment if operating at low frequency for too long.[36] The ERCOT system frequency dropped below 59.4 Hz for 4 minutes and 23 seconds (Figure 2.j) on the morning of February 15. Consequently, the grid was within minutes of a much more serious and potentially complete blackout on the morning of February 15.

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[30] Electric grids operate using the principle known as alternating current, or AC. North American grids, including ERCOT, are designed for current and voltage to oscillate at a frequency of 60 cycles per second, or 60 Hz.

[31] If grid frequency falls below 59.9 Hz, this generally indicates that load is large relative to demand.

[32] ERCOT Nodal Operating guide, June 15, 2019 Section (http://www.ercot.com/content/wcm/libraries/182971/June_15__2019_Nodal_Operating_Guides.pdf) Section 2.6 Requirements for Under-Frequency and Over-Frequency Relaying, 2.6.1 Automatic Firm Load Shedding, paragraph (1)

[33] Importantly, ERCOT makes other non-automated (by engineering devices) decisions to trigger actions to stabilize the grid before grid frequency reaches 59.3 Hz (e.g., call on responsive reserve and non-spinning reserve capacity).

[34] See ERCOT glossary: http://www.ercot.com/glossary. EEA: Energy Emergency Alert

[35] http://www.ercot.com/services/comm/mkt_notices/opsmessages/2021/02

[36] About 1,800 MW of (mostly coal and natural gas) generators listed frequency issues as the reason for tripping offline during the winter event, even though, according to ERCOT protocols (Table 2.a of this report), the frequency deviation shouldn't have tripped any under-frequency relays that are designed to automatically disconnect the power plant from the grid to physically protect itself. However, at some power plants, rapid increases in exhaust and boiler pressures occurred from equipment responding to grid frequency changes. Those fluctuating power plant conditions in turn tripped other safety mechanisms that took generators offline. Some large thermal generation units require days to fully cool off before they can be restarted.

Table 2.a. Table from Section 2.6.2 of ERCOT Nodal Protocols indicating the allowed settings for under-frequency relays installed on Generation Resources.[37]

Frequency Range	Delay to Trip
Above 59.4 Hz	No automatic tripping (Continuous operation)
Above 58.4 Hz up to And including 59.4 Hz	Not less than 9 minutes
Above 58.0 Hz up to And including 58.4 Hz	Not less than 30 seconds
Above 57.5 Hz up to And including 58.0 Hz	Not less than 2 seconds
57.5 Hz or below	No time delay required

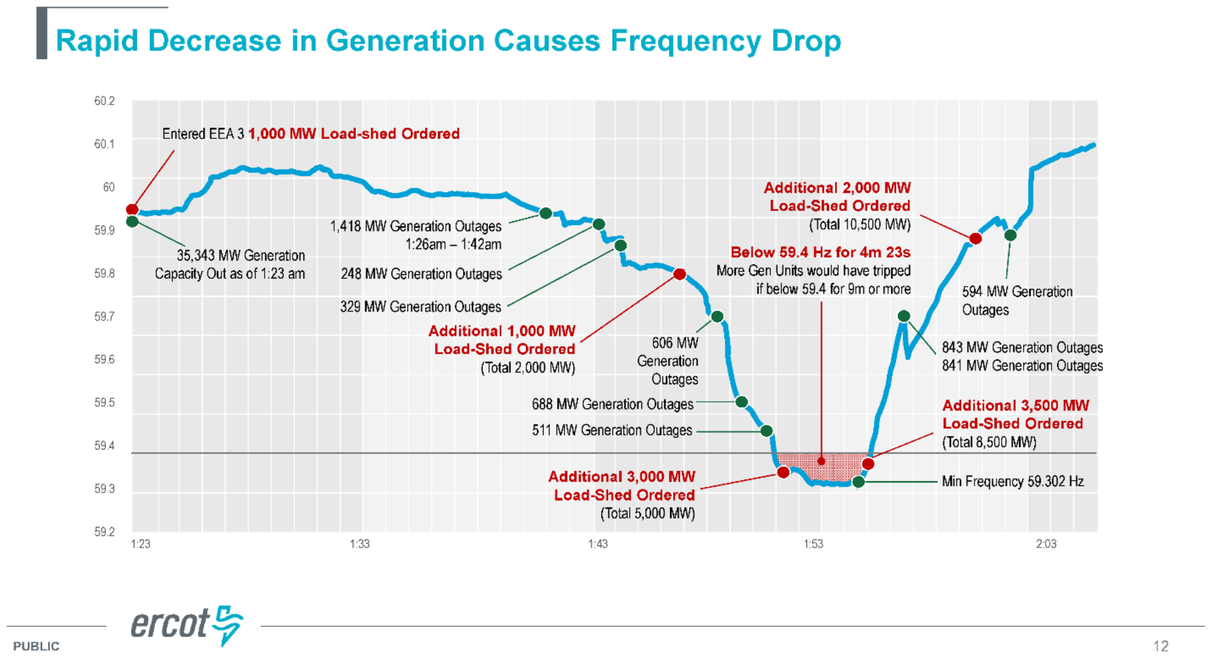

Figure 2.j. The ERCOT grid frequency during the critical time of load shedding and generation capacity outages on the morning of February 15, 2021 (ERCOT, 2021).

Figure 2.k shows the high level status of the grid from February 12 to February 20, including what load would have been absent blackouts, the actual served load, total renewable and thermal (nameplate) outages, as well as the level of load shed (blackouts).

[37] Note that we are presenting certain figures that were created by the ERCOT staff in this document, in situations where have been able to review and confirm the underlying data used in the creation of those figures.

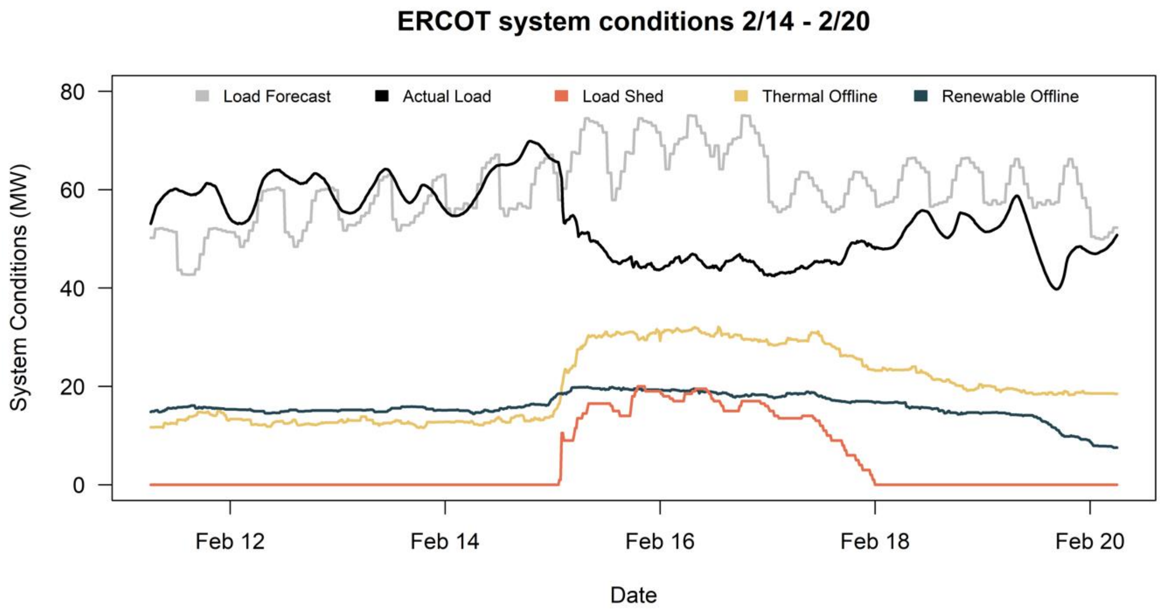

Figure 2.k. Hourly time sequence of forecasted load, actual load, and power plant capacity offline from Feb 11-19, 2021.[38]

Absent load shed, ERCOT back casted demand to peak at roughly 76,800 MW,[39] about 19,120 MW higher than the value expected under normal winter weather (57,699 MW) and more than 9,500 MW higher than ERCOT's "Extreme Peak Load" SARA scenario.[40] However, not only was demand underestimated, but supply was overestimated, as discussed in the following section.

2.4. Generation Outages (Timeline)

ERCOT has publicly released data regarding which power plants went offline and when[41] and also aggregated capacity that was offline by cause of outage as categorized (largely) by power plant operators.[42]

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[38] Data from ERCOT's hourly load data archives as well as various public reports and datasets provided by ERCOT. See http://www.ercot.com/news/february2021.

[39] http://www.ercot.com/content/wcm/lists/227689/Available_Generation_and_Estimated_Load_without_Load_Shed_Data.xlsx

[40] http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.xlsx

[41] http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx.

[42] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

Going into the early morning of February 15, generation outages (nameplate) were already high at roughly 30,000 MW. By 9:00 a.m., total outages and derates[43] increased to over 50,000 MW, or roughly 40% of the total installed nameplate capacity in ERCOT. Levels of outages and derates would change over the event, but would not return to pre-blackout levels until the afternoon of February 19. Figure 2.l shows outages and derates of power plants by cause (as reported to ERCOT by generators, with some possible interpretation by ERCOT), based on nameplate capacity.

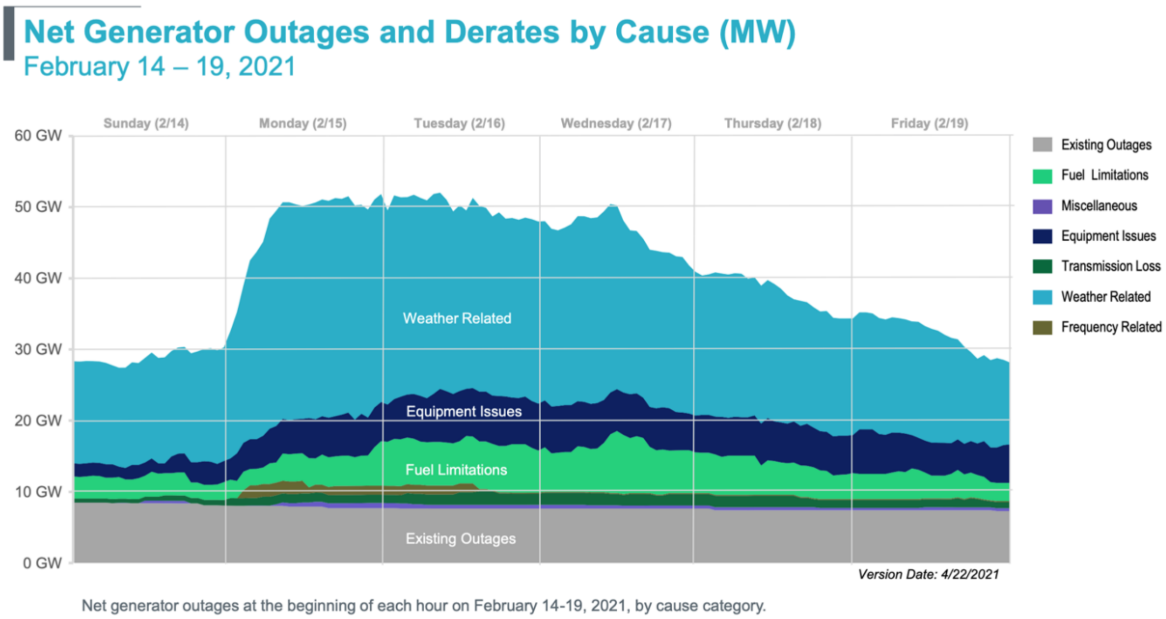

Figure 2.l. Net capacity outages and derates by category of failure mode, when considering the rated nameplate capacity of all power plants. Figure by ERCOT.[44]

As the extreme cold weather settled over the entire state, the outages increased. From noon on February 14 to noon on February 15, the offline renewable capacity increased from 15,100 MW to 19,400 MW (+4,300 MW) and the total outages of thermal generators increased from 13,700 MW to 31,100 MW (+17,400).[45]

Figure 2.m shows the spatial temperature and generation outages across Texasduring the critical hour when grid frequency was declining on the early morning of February 15, and the time of peak generation capacity outages on February 16.[46] As the

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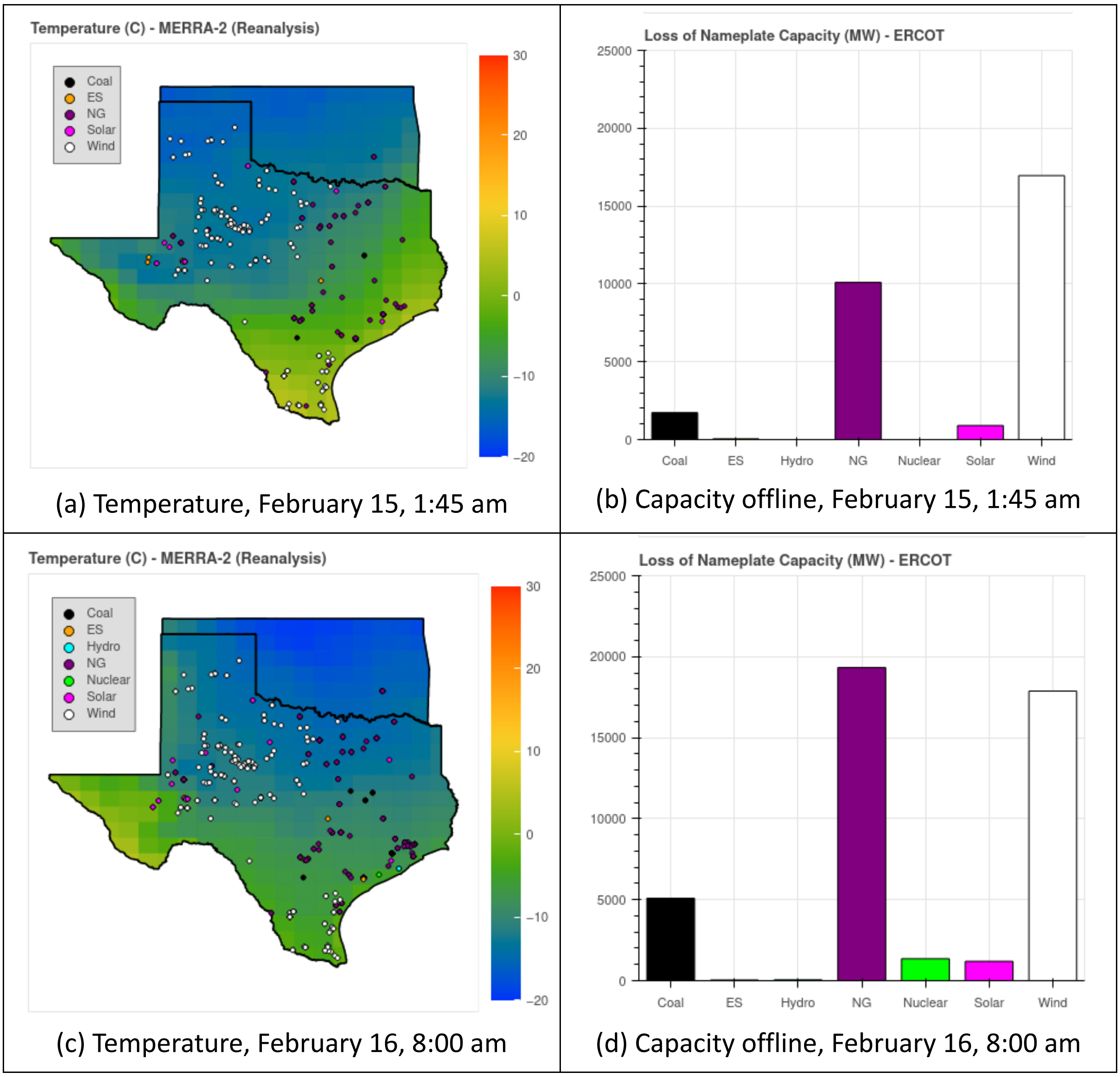
[43] A derated power plant is one that is able to produce some level of power output, but it not able to produce at its full potential. For example, some natural gas power plants weren't able to get enough gas to run at 100% output, but were still able to produce some power at a lower level, thus the power plant was derated.

[44]http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf

[45] Values rounded to nearest 100 MW.

[46] Temperature data come from the National Atmospheric and Space Administration (NASA) Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA-2): https://goldsmr4.gesdisc.eosdis.nasa.gov/data/MERRA2/.

colder temperatures moved further south into Texas, so did generation outages. Moreover, the types of outages changed.



(a) Temperature, February 15, 1:45 am

(b) Capacity offline, February 15, 1:45 am

(c) Temperature, February 16, 8:00 am

(d) Capacity offline, February 16, 8:00 am

Figure 2.m. The temperature across Texas and reported loss of (nameplate) capacity by ERCOT for the critical time period of February 15, 1:45 am (a and b) and the time of peak generation outage on February 16, 8:00 am (c and d).[47]

Generator outage data, as reported to and summarized by ERCOT, suggest that the largest share of outages was weather-related. The capacity that went offline due to weather-related[48] causes doubled from 15,000 MW at noon on February 14 to

[47] Each circle in subfigures (a) and (c) indicates the location of power generation units that are offline or derated, and its color corresponds to the capacity in subfigures (b) and (d). Temperature data come from the MERRA2 reanalysis data set.

[48] ERCOT defines outages which are weather-related in the following manner: “This includes but is not limited to frozen equipment—including frozen sensing lines, frozen water lines, and frozen valves—ice accumulation on wind turbine blades, ice/snow cover on solar panels, exceedances of low temperature limits for wind turbines, and flooded equipment due to ice/snow melt.”

30,000 MW at noon on February 15. In total, about 167 units listed their outages as weather-related during the event. Beyond wind turbine icing, outages between February 14 and 15 were mainly the result of frozen water intakes and sensing lines and the freezing of other general equipment. As freezing weather persisted further, other problems arose — for example, there were issues around control and condensate systems that caused more capacity to go offline. At least two black start-rated units reported outages or derates for weather-related reasons. [49]

The second largest reported category of offline capacity was existing outages, including scheduled and planned outages, mothballed units, and forced outages that started before the February 8 OCN. At noon on February 14 approximately 8,400 MW of capacity was offline due to existing outages. The majority of this capacity (7,700 MW) was from coal and natural gas power plants. The total amount of these pre-existing outages steadily declined to 7,300 MW by the end of the event.

"Equipment issues" accounted for the third highest amount of power plant outages and derates. Equipment issues were the cause of 1,900 MW of outages at noon on February 14, rising to 5,600 MW by noon on February 15. In total, equipment issues were listed as the reason for outages at about 146 units. A survey of unit-specific outage data indicates that these power plants went offline because of equipment failures that were not directly associated with the weather, for example clogged sensing lines and stuck valves due to normal wear and tear.[50] At least six black start-rated units reported outages or derates based on equipment failures.

Fuel limitations account for the fourth-most capacity outage and derating, with 131 units listing this reason for their outage.[51] Fuel limitations mostly affected natural gas plants and coal plants. Fuel issues for natural gas existed before the blackouts began (3,500 MW at noon on February 14) and increased as the event continued (6,700 MW at 10:00 a.m. on February 17). While there were no fuel-related outages associated with coal on February 14, issues appeared on February 15 and caused the outage of a maximum of 2,100 MW at 4:00 p.m. on February 16. Lack of fuel, low fuel pressure,[52] and fuel contamination were the major listed reasons for fuel-related outages for natural gas-fired generation units. Detailed, unit-specific, power plant outage information indicates that power plants with both "firm" and "non-firm" fuel

[49] Black start generation units are those able to start generation on their own, without support of the ERCOT transmission grid, as if there was absolutely no electricity generation on the grid (i.e., the grid is off, or "black" with no lights).

[50] Equipment failures such as these also happen in the summer when older power plants that don't run often are pressed into service to meet peak demand.

[51] Fuel limitation issues later matched or exceeded equipment issues by February 16.

[52] Some power plants were able to derate with lower fuel pressures, but others had to turn off completely.

supply contracts experienced fuel supply/curtailment issues. Also, at least five black-start-rated units reported outages or derates based on fuel supply issues.

Generator reports to ERCOT indicate that natural gas fuel shortages preceded the firm load shed directives from ERCOT, occurring as early as February 10. These fuel limitations affected more generation capacity as the cold weather event continued. At least as early as February 8, ERCOT began notifying QSEs of potential weather issues and instructed them to notify ERCOT of any known or anticipated fuel restrictions. ERCOT has an arrangement with at least one natural gas supplier to provide e-mail notifications when gas supply restrictions are issued to its natural gas-fired electric generation facilities. ERCOT received such notices as early as February 9 for supply restrictions starting the morning of February 10. Additionally, ERCOT received a notice on February 10 of supply restrictions for parts of Texas that would completely cut off power plants from fuel delivery and would start on February 12.

Additional natural gas outages are potentially due to the loss of electricity affecting the ability of the natural gas infrastructure to operate and thus deliver fuel, but we did not have data to evaluate the magnitude of this interdependence, or determine causality. Public testimony from Oncor's CEO indicated that not all infrastructure that was critical to the natural gas supply chain was registered with them as critical load not to be turned off.[53] He stated that Oncor started the event with 35 pieces of critical natural gas infrastructure on their "do not turn off" list, but added 168 more by the end of the event. This presumably indicates that some delivery of natural gas may have been interrupted due to power outages because the operators of the critical natural gas infrastructure failed to alert the transmission and/or distribution providers (TDSPs)[54] that they were critical loads.

The detailed outage data also suggest that transmission and substation outages led to generation outages reaching 1,900 MW of wind and solar on February 16. No coal, natural gas, or nuclear generation units listed transmission outage as a reason for an outage or derate. In all, 18 solar and wind units listed transmission losses as their reason for outage or derating. Additional data from ERCOT indicate that on February 9 the grid operator identified 28 existing transmission outages that could be cancelled or withdrawn by February 12, and all outages planned to begin between February 12-17 were moved, cancelled, or withdrawn. While it is likely that the grid could have operated in a more stable manner with fewer planned transmission outages, it is unknown how much worse, if at all, the situation would have been had these outages been allowed to proceed.

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[53] https://www.texastribune.org/2021/03/18/texas-winter-storm-blackouts-paperwork/.

[54] Section 2 of ERCOT protocols defines Transmission and/or Distribution Service Provider as: "An Entity that is a TSP, a DSP or both, or an Entity that has been selected to own and operate Transmission Facilities and has a PUCT approved code of conduct in accordance with P.U.C. SUBST. R. 25.272, Code of Conduct for Electric Utilities and Their Affiliates." DSP = distribution service provider.

Grid frequency deviations were reported to be responsible for up to 1,800 MW of outages (8 total units), mostly coal, at 2 a.m. on February 15.

Figure 2.n aggregates all the causes of outages and shows the total amount of outages by fuel, based on nameplate capacity. From noon on February 14 to noon on February 15, the amount of offline wind capacity increased from 14,600 MW to 18,300 MW (+3,700 MW).[55] Offline natural gas capacity increased from 12,000 MW to 25,000 MW (+13,000 MW). Offline coal capacity increased from 1,500 MW to 4,500 MW (+3,000 MW). Offline nuclear capacity increased from 0 MW to 1,300 MW, and offline solar capacity increased from 500 MW to 1100 MW (+600 MW).

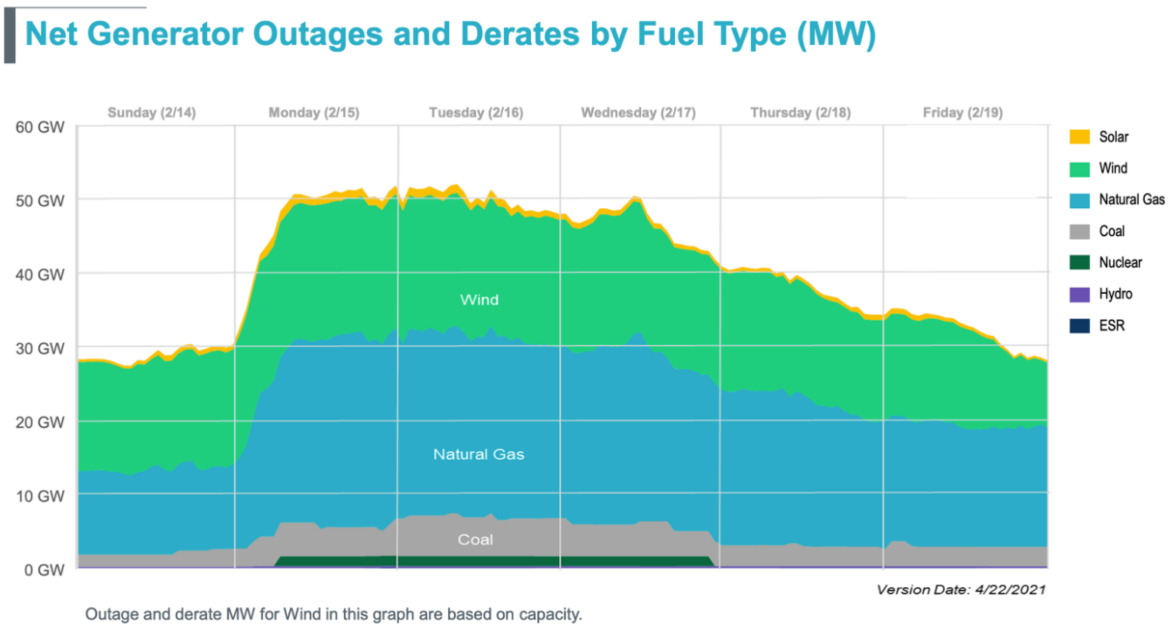

Figure 2.n. Net capacity outages and derates by fuel type, relative to the rated nameplate capacity of all power plants. Figure by ERCOT.[56]

Since rated nameplate capacities of wind and solar plants refer to the maximum amount of generation possible, derates based on these capacities overstate the amount of lost power generation due to the winter storm. Figure 2.o accounts for this by showing the same information as Figure 2.n based on the wind and solar capacities that would have been available based on back casted modeling that uses actual wind speed and solar radiation data to estimate what would have been

[55] Nameplate capacity for wind and solar is not representative of the amount of power generation expected when the unit is not expiencing an outage, but is much closer for the thermal fleet. When accounting for backcasted values of the available wind and solar radiation, available wind capacity outages actually decreased from 9,070 MW to 5,020 MW (-4,050) over the same time period and solar outages increased less from 108 MW to 545 MW (+437 MW).

[56] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

produced had all of the available wind and solar capacity been online.

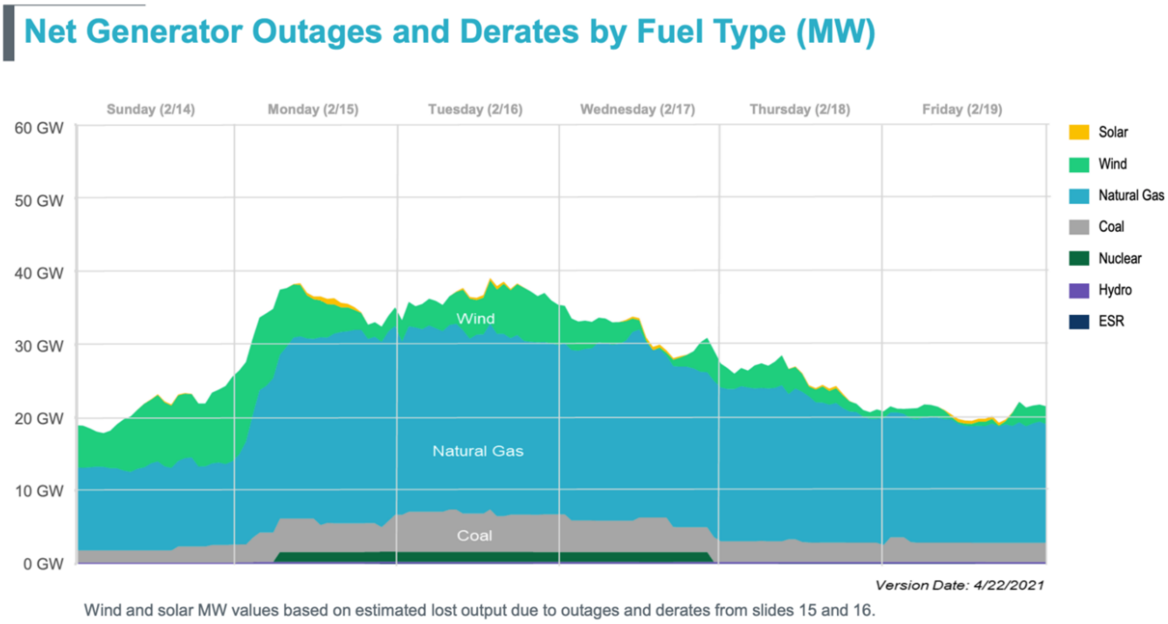

Figure 2.o. Net capacity outages and derates by fuel type, relative to expected contribution from wind and solar. Since wind and solar are not expected to generate at their nameplate capacity rating, the value derating shown here is less than that for wind and solar in Figure 2.n. Figure by ERCOT.[57]

Prior to the event, the Department of Energy and the Texas Commission on Environmental Quality issued directives to ERCOT that allowed the grid operator to dispatch certain power plants even if they would exceed pollution limits. The grid operator calculated that these directives enabled additional generation units to contribute an additional 1,400 MW of capacity, subject to outages and derates.

2.4.1. Generator Temperature Ratings Relative to Experienced Temperatures

This section combines data from ERCOT's public file of generator outages released on March 12, 2021 with weather data and confidential temperature ratings of power plants.[58] The purpose is to provide a high level view of whether some power plants failed above or below their low temperature ratings (see Figure 2.p). This section is not meant to provide a fully rigorous analysis of power plant failures as we only compare temperatures and not, for example, the enhanced cooling effects of wind,

[57] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

[58] For power plants that experienced an outage during the event, ERCOT sent Requests for Information (RFIs) to assess their causes. These RFIs included the question: "What is the minimum ambient operating temperature that the unit can start and continue to run without a unit trip or derate?" Some generators responded with "Unspecified" or "Unknown", but some were able to provide the minimum operating temperature, by unit, which were used here for comparison.

humidity, or ice. Also, *we only plot data for a subset* of the power plants listed in ERCOT's public file of generator outages.

The weather data are from the National Atmospheric and Space Administration (NASA) Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA-2) database. The MERRA-2 reanalysis weather database consists of atmospheric reanalysis data based on multiple types of historical observations. The data has an hourly time resolution and the reanalysis spans 1980-present. To relate a given power plant to a temperature in the MERRA-2 database, we assume the experienced power plant temperature is the same as the closest MERRA-2 temperature (example temperature distributions by grid cell are in Figure 2.m).[59]

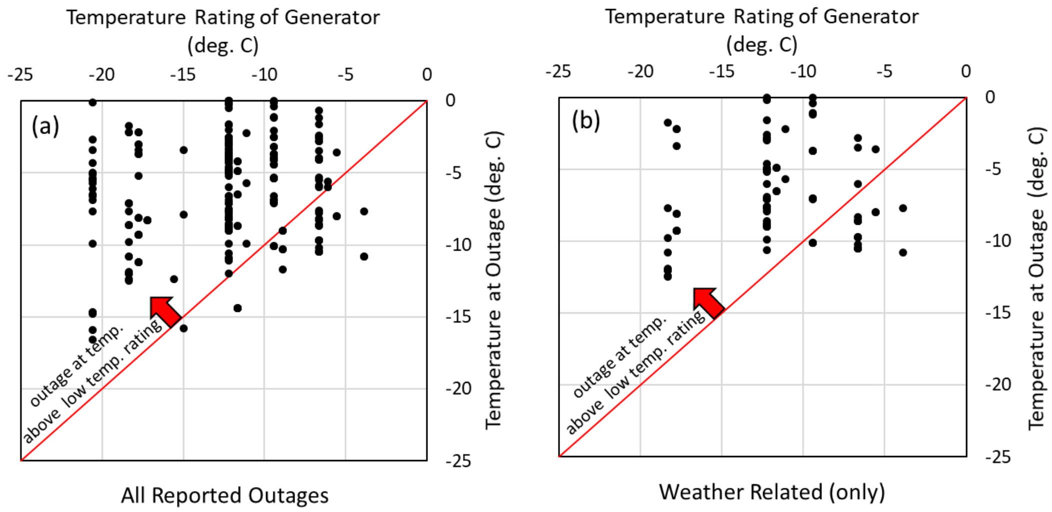

Figure 2.p. Plots of the estimated temperature experienced at outage for a subset of thermal power plants that experienced an outage or derate versus the lowest rated (design) temperature of power generation units (as reported by generation operators to ERCOT and FERC) for the winter event of February 10-20, 2021. We present the data in two charts: (a) generation units experiencing outages for any reason, (b) generation units experiencing outages summarized as "weather related" by ERCOT. Electric generation units were chosen at random.

Each dot in Figure 2.p represents a single generation unit listed in ERCOT's public data file of power plant failures. We include two charts in Figure 2.p, all the power plants that we compared (a) and the subset that reported their outage as being "Weather Related." The red line represents the boundary where the power plant design temperature equals experienced temperature. **A data point above the red line** means that a generation unit experienced an outage or derating at a temperature above its minimum temperature rating. **A data point below the red line** means that a generation unit experienced an outage or derating while experiencing a temperature below its minimum design temperature rating. Thus, in this simple analysis, data

[59] More precisely, the temperature is associated with the centroid of the MERRA-2 0.5° × 0.625° grid with the shortest Euclidean distance to the latitude and longitude of the power plant.

points above the red line indicate that some generation units might not have met their temperature design criteria. [60]

2.5. Load Curtailment, Requested and Achieved

As the freezing temperatures increased demand for electricity-based heating of homes and other buildings, ERCOT, the TDSPs, load-serving entities, and customers undertook a variety of actions to reduce demand on the system during the winter event, including:

- Involuntary load reduction due to selective outages of distribution circuits or substation loads chosen by the TDSPs and directed by Transmission Operators (TO)[61] when ERCOT issues load shed orders.
- Customer response to high market prices by customers exposed to wholesale electricity prices or natural gas prices.
- Deployment of load resources.
- Deployment of ERCOT's Emergency Response Service (ERS) program.
- Automated load shed triggered by under-frequency relays.
- Deployment of various demand response (DR) programs by load-serving entities.

2.5.1. Involuntary Load Shed

Per its Protocols, ERCOT declares an EEA Level 3 if operating reserves cannot be maintained above 1,375 MW. If conditions do not improve, continue to deteriorate, or operating reserves drop below 1,000 MW and are not expected to recover within 30 minutes, ERCOT orders transmission providers to reduce demand on the system.[62] The TDSPs are charged with making the final decision on which circuits to turn off to achieve the demand reduction. Each Transmision Operator (TO) is responsible for a predetermined percentage of the total load shed that ERCOT calls for in its "ERCOT

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[60] We note a few important caveats for interpreting this figure. The figure does not indicate the minimum temperature actually experienced by any given power plant, which is likely lower than the temperature displayed, but its minimum design temperature and the temperature at which it experienced an outage. Also, the figure has no information about precipitation (rain, ice, snow, fog) which could have been a crucial factor in any given power plant outage or derating. Also, only natural gas, coal, and nuclear generation units are shown in this figure. In particular, most wind power outages related to ice accumulation which was a combination of subfreezing temperatures and precipitation or fog.

[61] A Transmission Operator (TO) is defined in Section 2 of ERCOT protocols as "A Transmission and/or Distribution Service Provider (TDSP) designated by itself or another TDSP for purposes of communicating with ERCOT and taking action to preserve reliability of a particular portion of the ERCOT System, as provided in the ERCOT Protocols or Other Binding Documents."

[62] http://www.ercot.com/content/wcm/lists/200198/EEA_OnePager_updated_9-4-20.pdf

Load Shed Table."[63] Each TO instructs its respective TDSPs to achieve its load shed obligation. The percentage of load reduction for each TO is based on the previous year's peak Loads for its respective Transmission Service Providers (TSP), as reported to ERCOT and modified annually.

EEA Level 3 with Firm Load Shed was called on February 15 at 1:25 CST.[64] Load shed orders increased to 20,000 MW by 19:00 on the February 15. An analysis of load data appears to confirm compliance with the involuntary load reduction instructions.[65]

2.5.2. Response to High Prices

ERCOT conducts surveys of load-serving entities to discern the number of energy consumers under price-sensitive electricity plans. Such plans might include real-time pricing (to directly expose a consumer to wholesale market prices), peak rebate proms (providing a rebate to consumers who reduce demand below baseline amounts at the request of the load-serving entity), or block and index pricing (where consumption in excess of a contractual amount is exposed to market prices, while consumption below that amount results in a credit based on prevailing market prices).

In 2020, over 100,000 accounts were under a real-time pricing or block and index pricing plan. The number of accounts under a peak rebate plan was over 94,000.[66]

In recent summer periods with overall high system peak demand and high electricity prices, ERCOT has estimated demand response based on these accounts to be in excess of 4,000 MW.[67] The amount of demand reduction due to high prices during this winter event is difficult to determine, since many customers lost service due to involuntary outages and for other reasons.

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[63] This ERCOT Load Shed Table is in Section "4.5.3.4, Load Shed Obligation" of the ERCOT Operating Guide. During February 2021, the language of Section 4.5.3.4 stated: "Obligation for Load shed is by DSP. Load shedding obligations need to be represented by an Entity with 24x7 operations and Hotline communications with ERCOT and control over breakers. Percentages for Level 3 Load shedding will be based on the previous year's TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually." As of July 1, the language of Section 4.5.3.4 has been amended.

[64] www.ercot.com/services/comm/mkt_notices/notices/2021/02

[65] See slides 4 and 5: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[66] http://www.ercot.com/content/wcm/key_documents_lists/214087/15._RMS_2020_4CP__Retail_DR_Analysis_Raish.v3.pptx.

[67] http://www.ercot.com/content/wcm/key_documents_lists/218751/DSWG_2020_4CP__Retail_DR_Analysis_Raish.pptx, slide 5.

2.5.3. Deployment of Load Resources

Large industrial energy consumers with the ability to curtail their demand on the ERCOT system are permitted to provide ancillary services. Roughly half of ERCOT's requirements for Responsive Reserve Services (RRS)[68] are met by load resources equipped with under-frequency relays that instantaneously curtail load when the frequency drops to 59.7 Hz. Resources providing this service must also be able to respond to verbal dispatch instructions. In February 2021, the amounts of RRS provided by loads averaged 1,259 MW, which is lower than the 1,548 MW resource provided in January 2021.[69] Some load resources are also eligible to provide Regulation Up,[70] Regulation Down,[71] and Non-Spinning Reserves,[72] though the amount that these services provided in February 2021 was small.[73]

An analysis of load data suggests that maximum load reductions from load resources were over 1,400 MW on February 15, 16, and 17, and just under that level on February 19.[74]

2.5.4. ERS Program

The ERS program was activated during the winter event to reduce demand on the system.[75] Customers enrolled in the program reduce their purchases from the grid by reducing load or by starting backup generators. These emergency resources are contracted to provide this service to ERCOT through four-month contracts, and have response times of 30 minutes or 10 minutes. Different amounts are procured in each of eight time periods (or hour blocks) spread among weekday and weekend days.

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[68] RRS provides an operating reserve from on-line generation resources that is responsive to frequancy based on governor action and responsive to any automated or verbal dispatch instructions from ERCOT within 10 minutes. Load resources providing RRS respond via underfrequency relays when system frequency drops below 59.7 Hz.

[69] http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13242&reportTitle=Monthly%20ERCOT%20Demand%20Response%20from%20Load%20Resources&showHTMLView=&mimicKey.

[70] Regulation Up provides an operating reserve that increases generation output (or reduces demand, if a load resource) in response to automated signals to balance real-time demand and resources.

[71] Regulation down provides an operating reserve that decreases generation output (or increases demand, if a load resource) in response to automated signals to balance real-time demand and resources.

[72] Non-spinning reserves provides an operating reserve that can be synchronized and ramped to a determined amount of generation or load reduction within 30 minutes of notice.

[73] http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13242&reportTitle=Monthly%20ERCOT%20Demand%20Response%20from%20Load%20Resources&showHTMLView=&mimicKey.

[74] See slide 7 at: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[75] http://www.ercot.com/services/programs/load/eils

Overall, the program achieved its targeted level of demand reduction of roughly 1,100 MW during the morning of February 15.[76] Some of the energy consumers in the program reduced their level of demand prior to the EEA Level 3 and deployment of ERS, as many businesses closed in anticipation of the storm. Some of the early demand reduction may have also resulted from public appeals for energy conservation, and local transmission and distribution system outages.

While the participating "loads" or consumers in the ERS program provided demand reduction well in excess of their obligations, ERS program participants contracted to provide generation during emergencies generally under-performed. The ERS generators met less than half of their obligation of around 300 MW in the early hours of February 15.[77] Performance of the ERS generators was reportedly hampered by "supply constraints, refueling issues, and forced outages."[78] Some generators in the ERS program indicated that they were not able to meet their requirements because they ran out of fuel (many have enough on-site fuel for only a few hours or days). Other ERS generators indicated that the distribution circuit through which they were served was turned off, so they were not able to provide power to the bulk grid.

2.5.5. Automated Load Shedding via Under-frequency Relays

Under-frequency load shed (UFLS) relays exist on the transmission and distribution grid. These are configured to trigger a circuit offline, and thus the customers on that circuit, if experiencing a frequency of 59.3 Hz or lower. At 59.3 Hz, under-frequency relays on the transmission and distribution grid can trigger automatic load shedding of up to 5% of the transmission operator's load (Table 2.b). Lower frequencies trigger even more UFLS.

Table 2.b. Table from Section 2.6.1 of ERCOT Nodal Operating Guide indicating the settings for Under-Frequency Load Shedding (UFLS) relays installed by Transmission Operators (TO).

Frequency Threshold	TO Load Relief
59.3 Hz	At least 5% of the TO Load
58.9 Hz	A total of at least 15% of the TO Load
58.5 Hz	A total of at least 25% of the TO Load

[76] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX. Per slide 3: "As an ERS fleet in aggregate, the response generally met or exceeded the aggregate obligation." Note that ERS obligations differ in different time periods within a day.

[77] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX. Slide 15.

[78] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX, slide 8.

Confidential responses of TDSPs to ERCOT requests for information note UFLS relay tolerances of +/- 0.01 Hz, and some TDSPs recorded frequencies between 59.300 and 59.310 Hz during the critical frequency period indicated in Figure 2.j. As reported by five of the major TDSPs in ERCOT, the total MW UFLS by automatic (by experiencing low frequency) triggering of relays was on the order of 200 MW for 2 to 3 dozen circuits.

In addition to automated triggering of UFLS relays, the TDSPs also included some circuits with UFLS relays in the so-called manual load shed in which they selected circuits to trip offline to meet their portion of the load shed obligation as commanded by ERCOT. There were over 1000 circuits (possibly more than 2000) with UFLS relays included in this manual load shed. Thus, the manual load shed affected two orders of magnitude more load, number of circuits, and customers than were triggered via automated UFLS. At all times the TDSPs were still required to have 25% of load on circuits with UFLS relays.

2.5.6. Deployment of Various Demand Response (DR) Programs by Load-Serving Entities

Many DR programs are operated by load-serving entities completely outside of ERCOT's formal markets. For example:

- CPS Energy operates a large portfolio of demand response programs that can achieve demand reductions of well over 200 MW during a typical summer deployment.[79]
- Austin Energy operates certain DR programs.[80]
- A number of retail electric providers operate programs that control thermostats to achieve residential demand reduction.[81]

Though the focus of these programs has historically been on reducing demand during the summer, at least one utility attempted to deploy their programs during the winter event to achieve whatever demand reduction might be possible.[82] The success of these efforts is not yet publicly-known.

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[79] https://www.sanantonio.gov/Portals/0/Files/Sustainability/STEP/CPS-FY2020.pdf, p. 11, Table 1-1.

[80] https://austinenergy.com/wcm/connect/5f6f5cdc-31bb-436c-a52f-a050d113b5d2/DemandResourceMWSavings-WP.pdf?MOD=AJPERES&CVID=mRLC6hb, pp. 15-17.

[81] For example: https://www.reliant.com/en/residential/electricity/save-energy/degrees-of-difference-rewards.jsp; https://www.txu.com/savings-solutions/txu-ithermostat.aspx

[82] See, for example: https://newsroom.cpsenergy.com/update-as-of-sunday-february-14-2021-400-pm-winter-weather-and-extreme-cold-puts-community-at-risk-state-grid-operator-and-cps-energy-call-for-customers-to-reduce-electric-and-natural-gas-use/.

2.5.7. Aggregate Levels of Demand Response

It is clear that a very large demand reduction was achieved during the February event through a combination of formal programs and involuntary load shed action, by the grid operator, TDSPs, load-serving entities, and individual consumers. ERCOT has estimated that over 32,000 MW of demand reduction was achieved through the sum of these actions when demand reduction peaked in the morning of February 16, while the previous day saw peak levels of demand reduction of over 28,000 MW.[83] However, it is not possible to specifically attribute the demand reduction to each of these specific actions. Involuntary load accounted for the majority of load shed, and these load shed actions by a TDSP limit the ability of a customer to respond to prices or take some other action, for example.

2.6. Natural Gas and Operations during February 2021

This section covers how the production and flow of natural gas changed during the event. It also provides context for the various end uses of natural gas among which total consumption is partitioned. For a primer on the balance of natural gas in Texas, see Appendix D.

2.6.1. Natural Gas Production

Per a February 25, 2021 report by the Energy Information Administration (EIA),[84] Texas natural gas production fell by almost half during Winter Storm Uri – from 21.3 billion cubic feet per day (Bcfd) during the week ending February 13, to about 11.8 Bcfd at its lowest point on February 17 (see Figure 2.q.). As a daily average over month, Texas dry natural gas production dropped from 21 in January 2021 to 13 Bcfd in February 2021.[85]

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[83] See slide 4 at: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[84] Texas natural gas production fell by almost half during recent cold snap - Today in Energy - U.S. Energy Information Administration (EIA)

[85] https://www.eia.gov/todayinenergy/detail.php?id=46896.

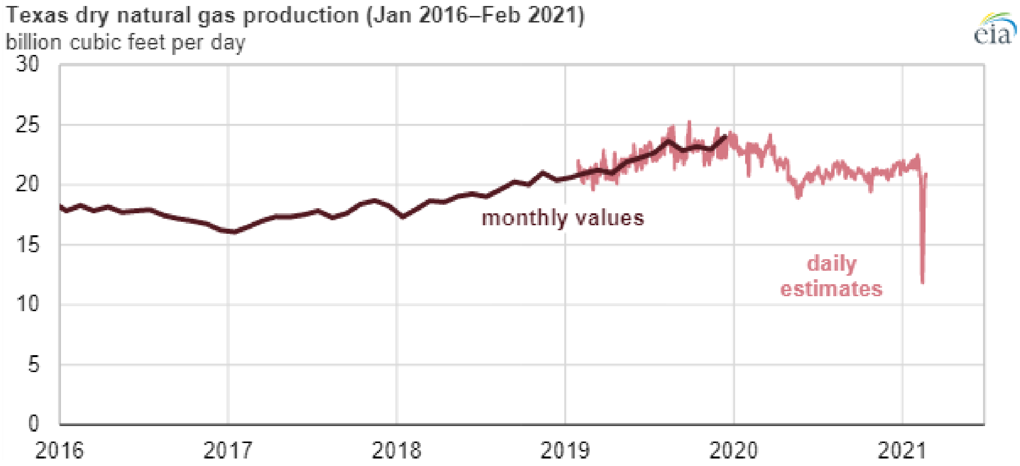

Figure 2.q. Texas Dry Gas Production through Jan 2016 – Feb 2021 (Source: EIA)

Based on a sample set of processing plants, located in the Permian, we also saw reduced residual gas[86] output from these plants during the week of the storm. Our sample includes 27 processing plants, with a total capacity 4.4 Bcfd, which is about 25% of the total 17 Bcfd capacity in the Permian Basin.

Two key observations arise from an examination of this sample set of processing plants:

- Per Figure 2.r, out of 27 gas processing plants in our sample, eight had zero output on February 15, 15 had zero output on February 16, and 18 had zero output on February 17.
- Figure 2.s shows the reported output from these 27 processing plants in February versus their inlet capacity. In early February, throughput was around 1.6 Bcfd, but declined to 1.4 Bcfd on February 12 and 13, and then on February 14, declined rapidly over the next three days to 0.257 Bcfd on February 16. This is an approximate 85% drop from the throughput level earlier in the month.

Since the Permian Basin produces about 50% of the dry production in the State of Texas and the data in Figure 2.s represent part of the processing plants from the Permian, the loss of production out of Permian Basin could have been close to 8 Bcf on February 13, which aligns with the reported single day drop of Texas from the EIA report. For the month of February, based on sample data, the daily average Permian gas processing could have been reduced by 6 Bcfd, or about 75% out of the reported 8 Bcfd reduction for Texas overall.

[86] Residual gas is the natural gas that is left after natural gas processing, which is free from impurities, moisture, natural gas condensates and is ready to be transported to the end user market through gas pipelines. Residual gas is also known as pipeline quality dry gas.

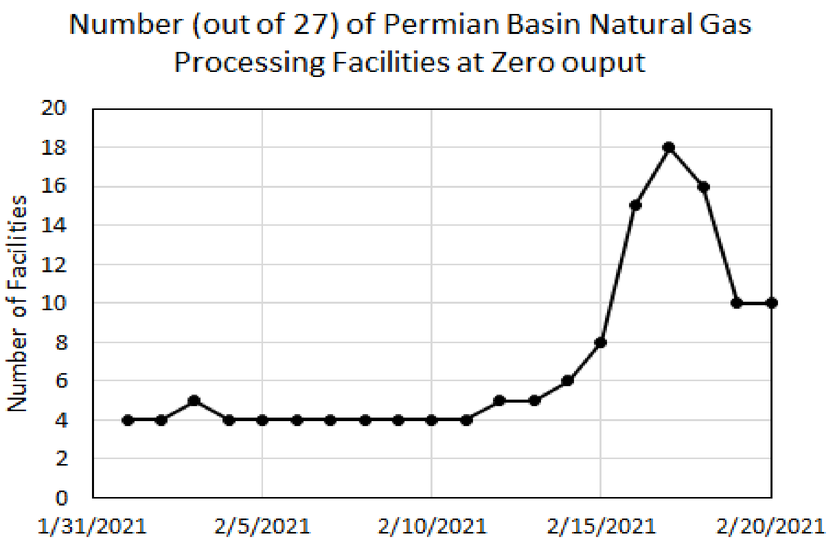

Figure 2.r. Number of Permian Basin natural gas processing facilities at zero output, out of our sample of 27 facilities. (Source: Wood Mackenzie)

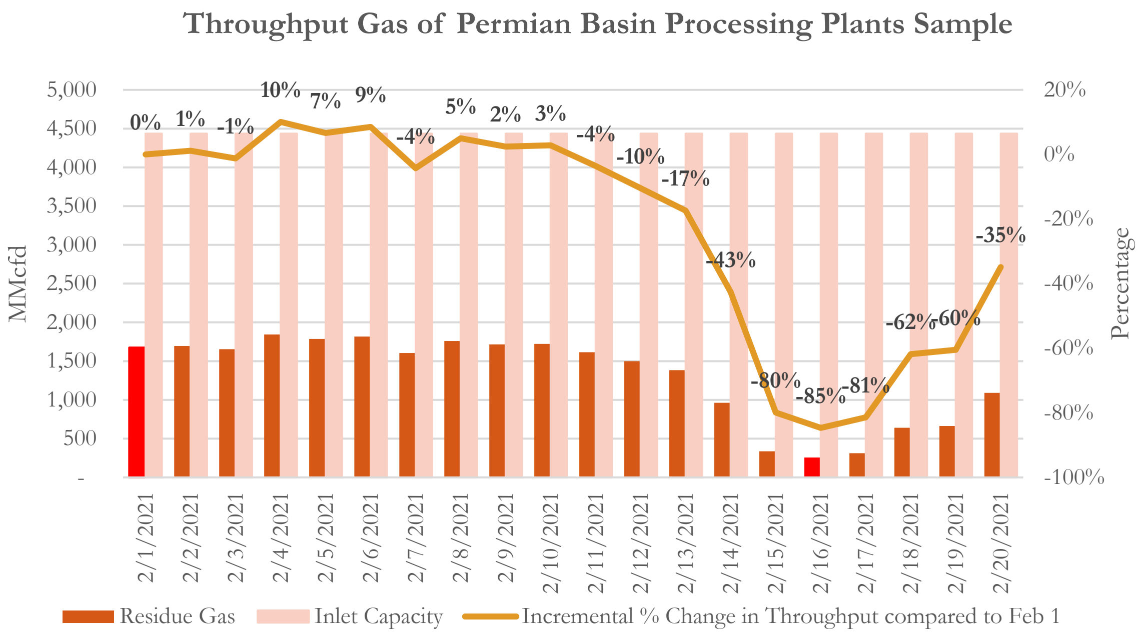

Figure 2.s. Throughput gas of Permian Basin processing plants out of our sample of 27 facilities. (Source: Wood Mackenzie)

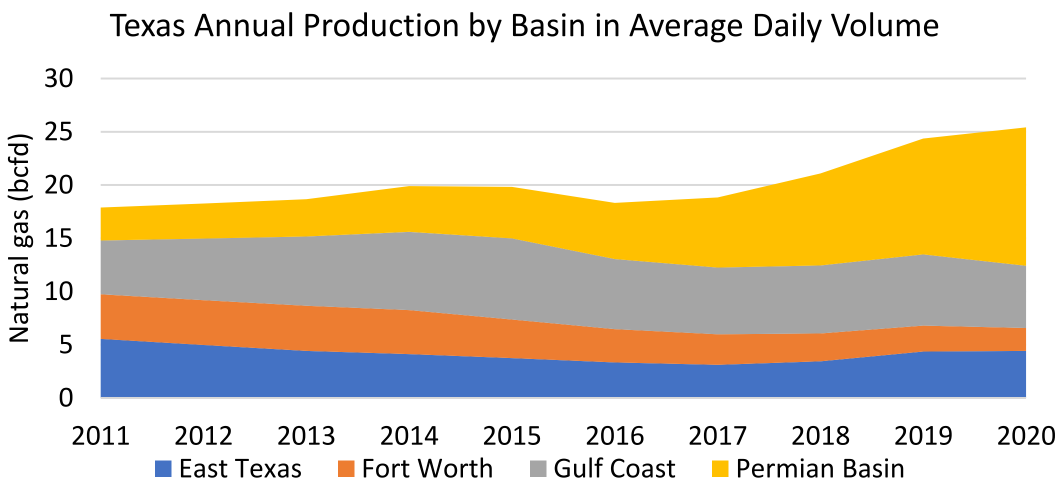

Figure 2.t. Texas natural gas production by basin since 2016 (Source: GPCM™)

The sample processing plant data indicates a severe reduction in dry gas production. There are two major factors contributing to the decline of dry gas production in Texas during the storm: frozen infrastructure and electric power interruptions.

Freeze-offs at wellheads can occur when unprotected wellheads experience sufficiently low ambient temperatures causing water and other liquids in the gas to form ice that can accumulate to such a degree as fill the entire cross-sectional area of pipes and prevent flow to the wellhead. The consequences can range from a minor inconvenience to major reductions in natural gas production. Wellheads in Texas are generally not hardened for freezing conditions.

Figure 2.t shows the trend of average daily Permian Basin natural gas production since 2011. During this time a higher percentage of gas production shifted to the Permian, avoiding some weather interruptions more frequent in the Gulf Coast region, such as hurricanes, but increasing vulnerability to cold weather. Furthermore, the Permian Basin gas generally has a higher water content, making it more prone to freeze in cold weather and form hydrates which can block the flow of gas.

It is also possible, and has been noted by some natural gas companies, that power interruptions to critical infrastructure contributed to a further decline in dry gas production during the week of the storm. Remote processing plants, especially larger ones (greater than 50 million cubic feet per day throughput), typically used to have on-site power generation, but more modern processing plants are often grid connected. The data indicate that natural gas output started to decline rapidly before the electricity forced outages (load shed) began early on February 15, with production declining about 700 million cubic feet per day (MMcfd) from February 8-14, (see Figure 2.s). This decline is likely due to weather-related factors and not a loss of power at natural gas facilities. However, some of the additional 600 MMcfd output decline from February 14-15 could be partly due to natural gas facilities residing on circuits that the TDSP selected to follow ERCOT's load shed orders.

2.6.2. Storage

According to the Texas Railroad Commission, there are 40 natural gas storage sites in Texas with a total maximum 17,536 MMcfd reported withdrawal rate.[87] Our sample data set[88] includes 5 interstate connected storage facilities and 7 intrastate connected storage facilities, covering about 25% of the state's total.

Figure 2.u shows the reported net flow rates for the observed interstate storage units and compares them to past years. The data show a significantly larger withdrawal of about 291,000 MMBtu/d[89] in February 2021, almost three times higher than that of February 2020. This high level of withdrawal leads to a historical low level of reserves for these storage units as shown in Figure 2.v. Based on the sample data, it appears that interstate gas storage inventory started to drop rapidly on February 9, with less than 10% of working gas storage remaining on February 18, and it was almost fully depleted by February 21 (see Figure 2.v and Figure 2.w).

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[87] Gas Storage Statistics website of the Texas Railroad Commission (April 2021 report, accessed June 24, 2021): https://www.rrc.texas.gov/gas-services/publications-statistics/gas-storage-statistics/.

[88] Based on the sample set, there is about 55% coverage of intrastate storage, while 10% of interstate storage data. The data set is based on available data from Genscape Wood Mackenzie.

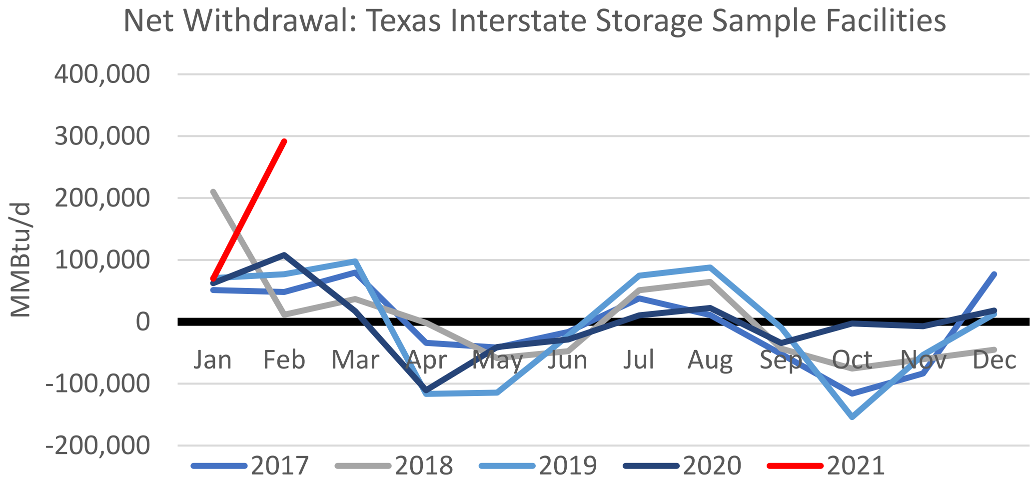

Figure 2.u. Net withdrawal rates (positive values indicate net withdrawal) as the daily average for each month for five Texas interstate storage facilities. (Source: Wood Mackenzie)

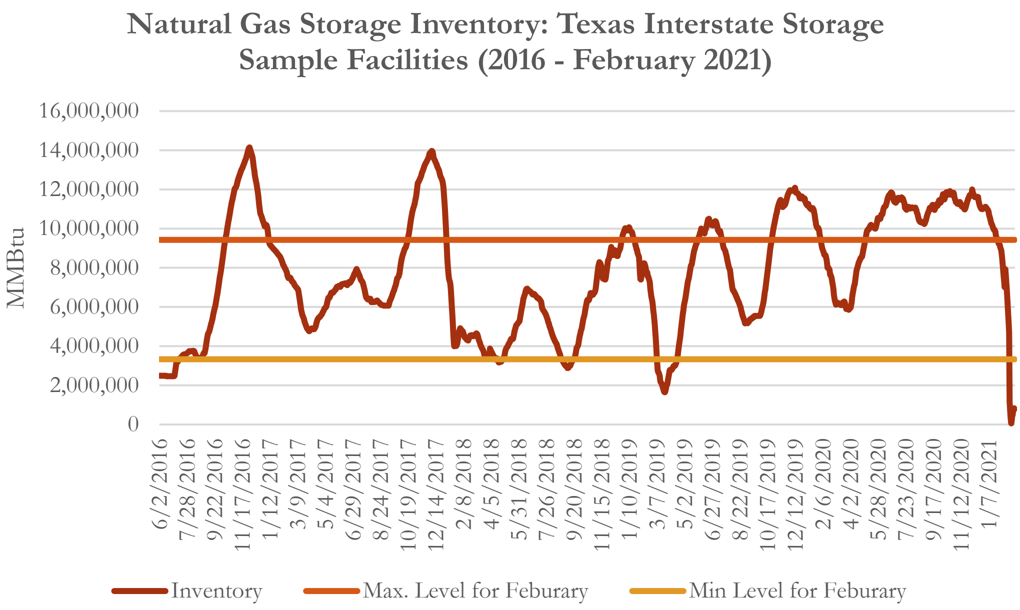

Figure 2.v. Texas natural gas storage inventory for our sample interstate storage facilities (2016 – February 2021) with lines indicating the maximum and minimum storage levels for the February months from 2016 to 2021. Note: 1 MMBtu ~ 1000 cubic feet of natural gas. (Source: Wood Mackenzie)

Figure 2.v and Figure 2.w (focusing on data for January and February 2021) show the total storage of natural gas for our sample interstate storage facilities, and Figure 2.x shows the withdrawal rates for those five facilities as a percentage of their historically-observed maximum withdrawal rates. Out of the five interstate storage units observed here, four experienced some level of increase of withdrawal during the winter event to reflect the higher demand for natural gas in the market. One of the four units, Unocal Keystone storage, experienced a large withdrawal the week of February 8. This could be a reflection of the early rise of the natural gas price which went above $4/MMBtu the week leading to the storm, which was already higher than usual.

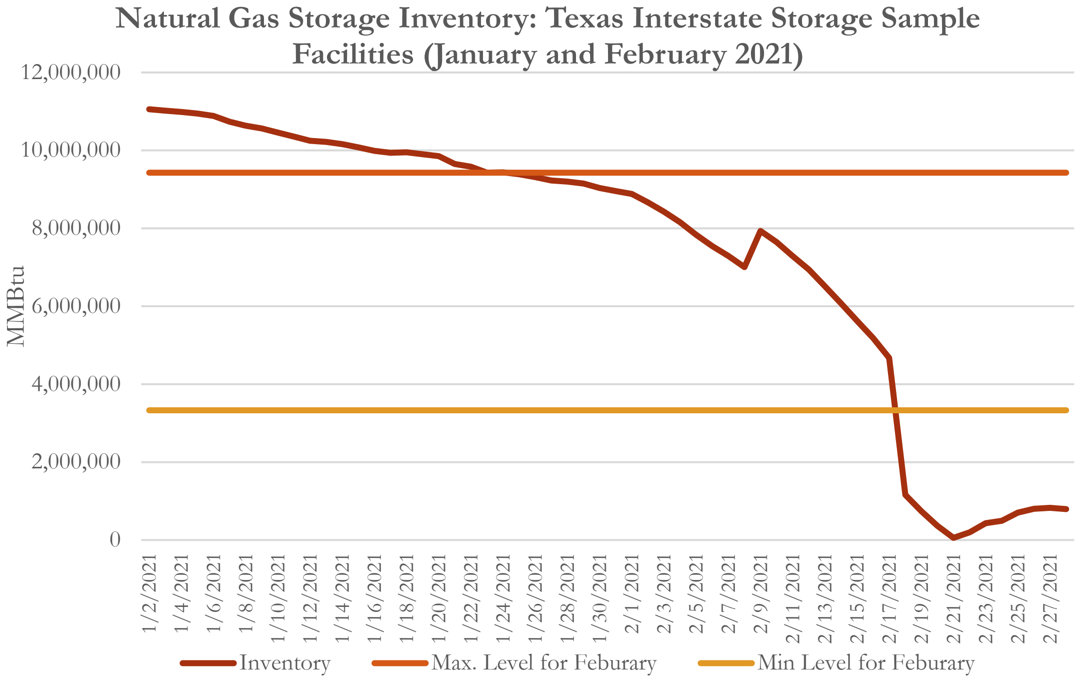

Figure 2.w. Texas natural gas storage inventory of for our sample interstate Storage facilities (January and February 2021). Note: 1 MMBtu ~ 1000 cubic feet of natural gas. (Source: Wood Mackenzie)

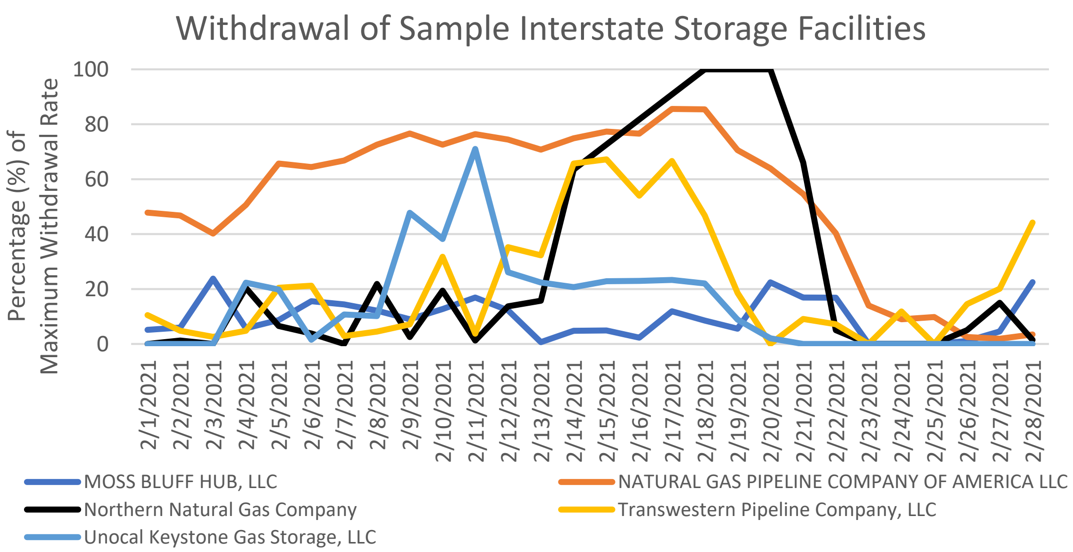

Figure 2.x. Natural gas withdrawal (as the percentage of maximum withdrawal rates) in February 2021 from each of our five sample interstate storage facilities. (Source: Wood Mackenzie)

Intrastate natural gas storage facilities also experienced high withdrawal rates through the week of the winter storm. However, the data for our sample of intrastate storage facilities indicate that during the week of February 13 their collective withdrawal rates never reached 100% of historically-observed maximum withdrawal rate capacities (Figure 2.y). These intrastate storage facilities also had higher than usual withdrawals before the beginning of the winter storm, on February 10, even at gas prices of $4 per million Btu (MMBtu). This drawdown of storage before February 14 contributed to the lack of natural gas supply going into the coldest parts of the storm and to the historically high natural gas prices during the storm that in some cases were 100 times higher than normal. *This situation leading into Winter Storm Uri was an extreme condition in which there was not sufficient gas delivery capability to prevent the extreme high price increase.*

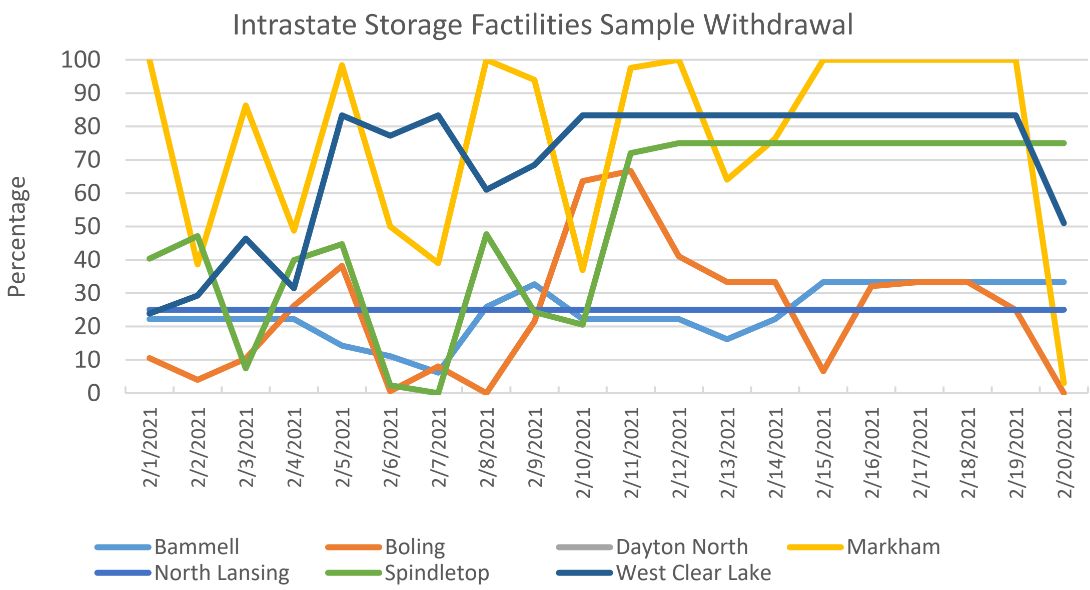

Figure 2.y. Natural gas withdrawal (as the percentage of maximum withdrawal rates) in February 2021 from each of our sample of intrastate storage facilities. (Source: Wood Mackenzie)

2.6.3. Natural Gas Demand

This section discusses the impacts on natural gas demand from the winter storm of February 2021. The dataset includes all sectors of demand in three categories, as labelled at interconnection point of the interstate pipeline network (delivery points). The dataset represents around 15% of the total consumption in Texas.

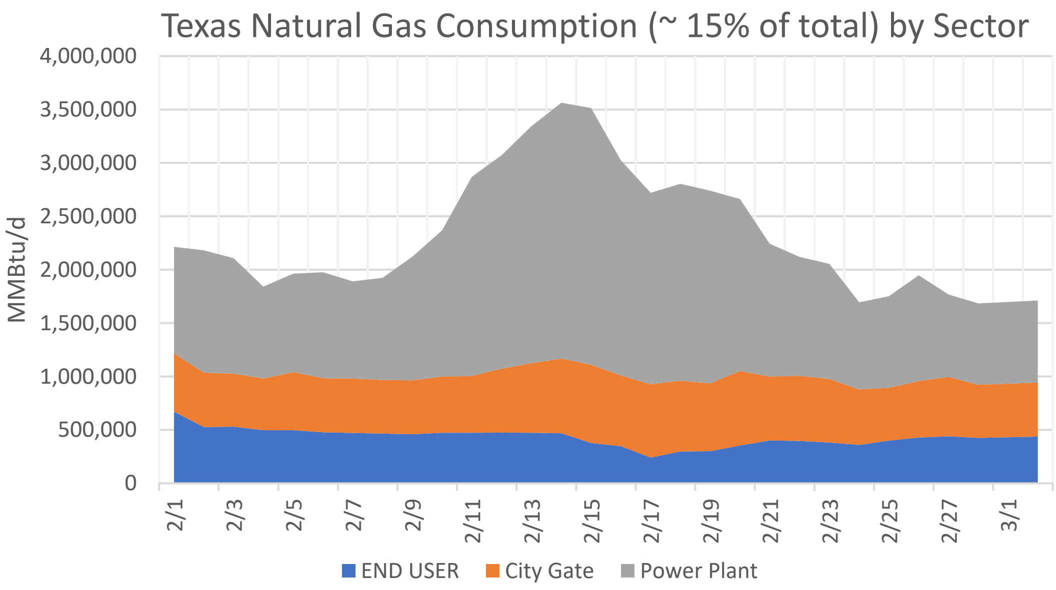

Figure 2.z. Texas daily natural gas consumption by sector (from our sample of interstate pipeline data) (Source: Wood Mackenzie)

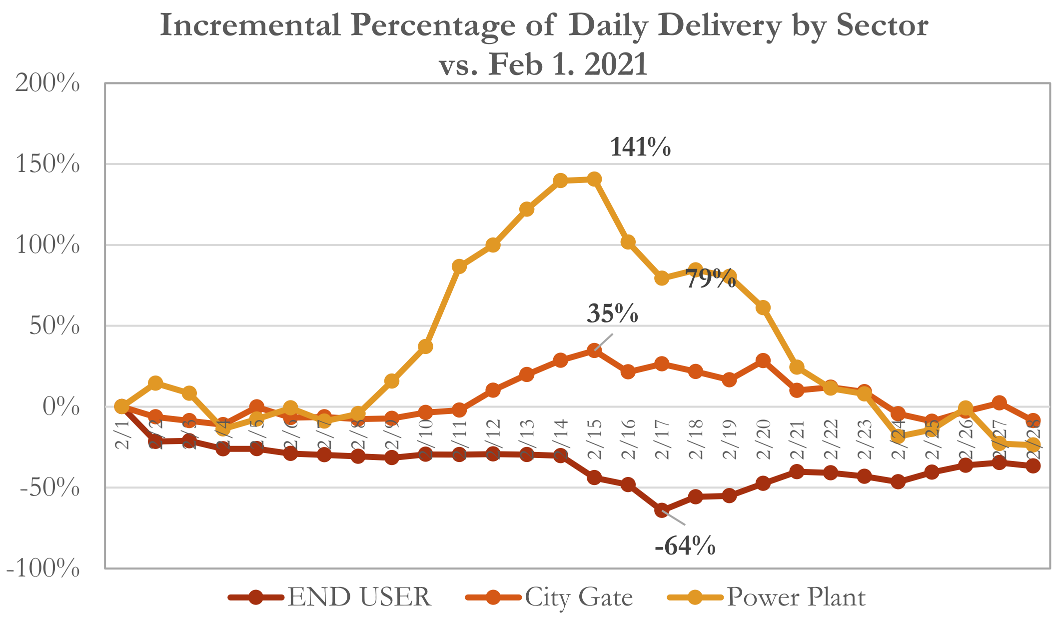

Figure 2.aa. Incremental change (in percentage) of daily natural gas delivery by sector relative to delivery on February 1, 2021, (Source: Wood Mackenzie)

Figure 2.z and Figure 2.aa show natural gas daily consumption in the sample Texas dataset by three sectors in February 2021,[90] representing overall changes and dynamics aggregated across three sectors. Figure 2.z indicates an aggregate increase in consumption peaking on February 14. Power plants and "city gate" (residential,

[90] "City gate" includes residential, commercial and some small industrial users. "Power Plants" represent connections to gas-fired power generators. Large industrial users are labeled as "End user" in the data.

commercial, and small industrial) consumers increased their natural gas consumption during the storm as industrial "end users" decreased consumption. This aligns with the Texas Railroad Commission's February 12, 2021 Emergency Order[91] that additionally prioritized natural gas to power generation just after the highest priority for residential customers and other buildings. Figure 2.aa shows the same consumption by sector as a daily percentage change versus first day of February, which provides an additional perspective on the change of consumption within each sector of gas delivery.

Figure 2.bb - Figure 2.dd show how the daily consumption of each sector in 2021 compares to past years. The consumption by large industrial users ("End Users" of Figure 2.bb) does not display a strong seasonal pattern of its demand of natural gas, but it has a higher likelihood to have interrupted demand from weather events or pandemic (see 2020 March through April). During Winter Storm Uri, the largest industrial consumers experienced the highest levels of natural gas curtailment. Relative to consumption on February 1, large industrial natural gas consumption declined by 30% on February 14 and dropped rapidly to its lowest level on February 17, to a 64% reduction. Compared to the past five years, the February 2021 curtailment in industrial sector demand is one of the biggest drops observed in the data.

City gate demand (Figure 2.cc), largely characteristic of residential and commercial demand, rose to a maximum of 730,000 MMBtu/d on February 15, which is about 35% higher than that on February 1. Natural gas consumption by power plants (Figure 2.dd) increased significantly from February 9 reaching about 140% of its February 1 level on February 14. While the natural gas system was able to significantly increase delivery during the cold weather conditions in the week ending on February 14, both city gate and power plants deliveries started to drop by February 15. As discussed elsewhere in the report, natural gas was already curtailed to some power generation facilities before February 14, and this aggregate decrease in deliveries to consumers indicates further constraints due to upstream reduction from production and storage.

[91] https://rrc.texas.gov/media/cw3ewubr/emergency-order-021221-final-signed.pdf.

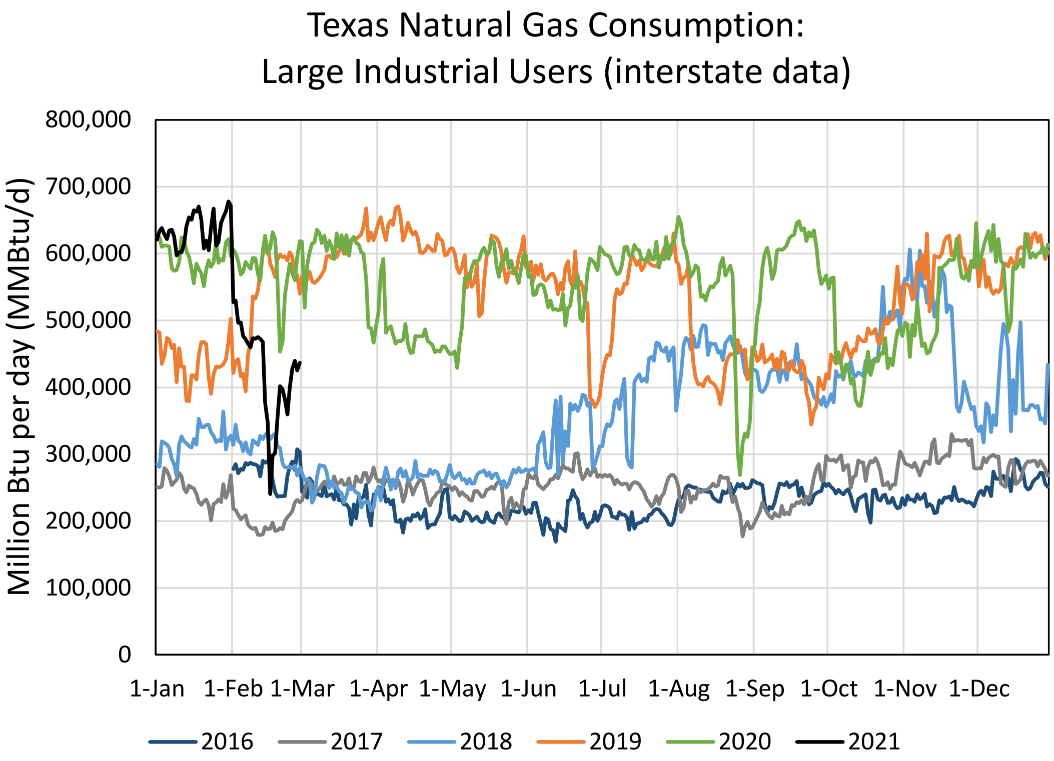

Figure 2.bb. Texas natural gas consumption for large industrial ("End User" in data set) via our sample of connection points to interstate pipelines (Source: Wood Mackenzie)

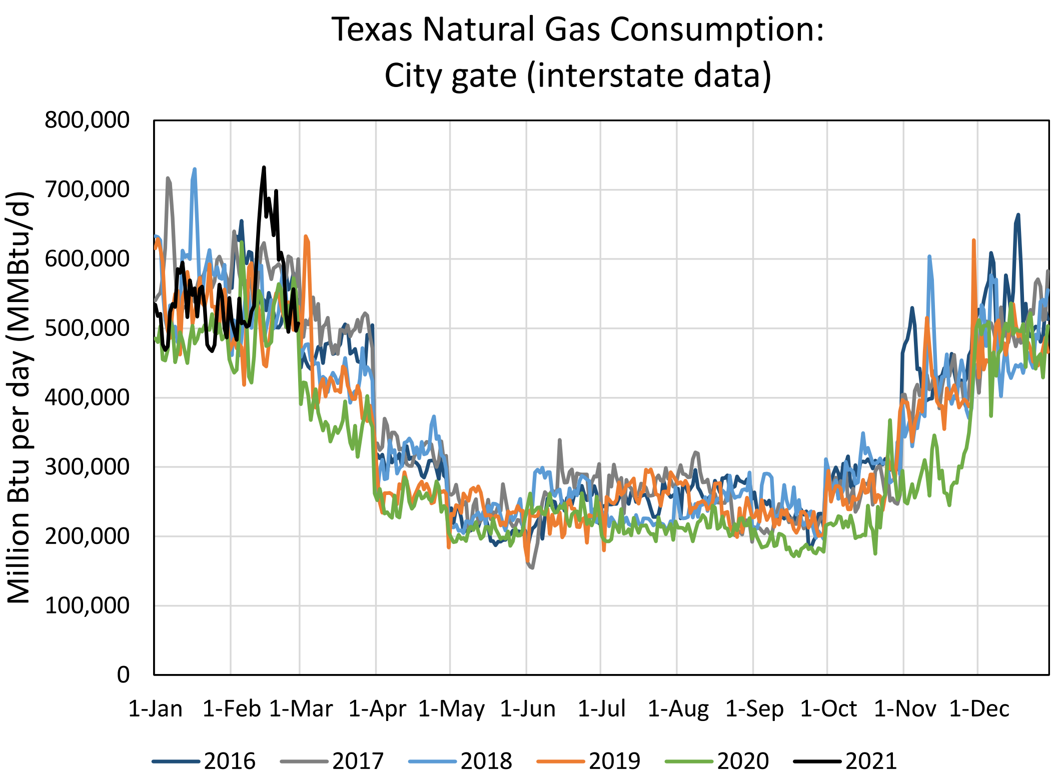

Figure 2.cc. Texas natural gas consumption for residential, commercial, and small industrial ("city gate" in data set) via our sample of connection points to interstate pipelines (Source: Wood Mackenzie)

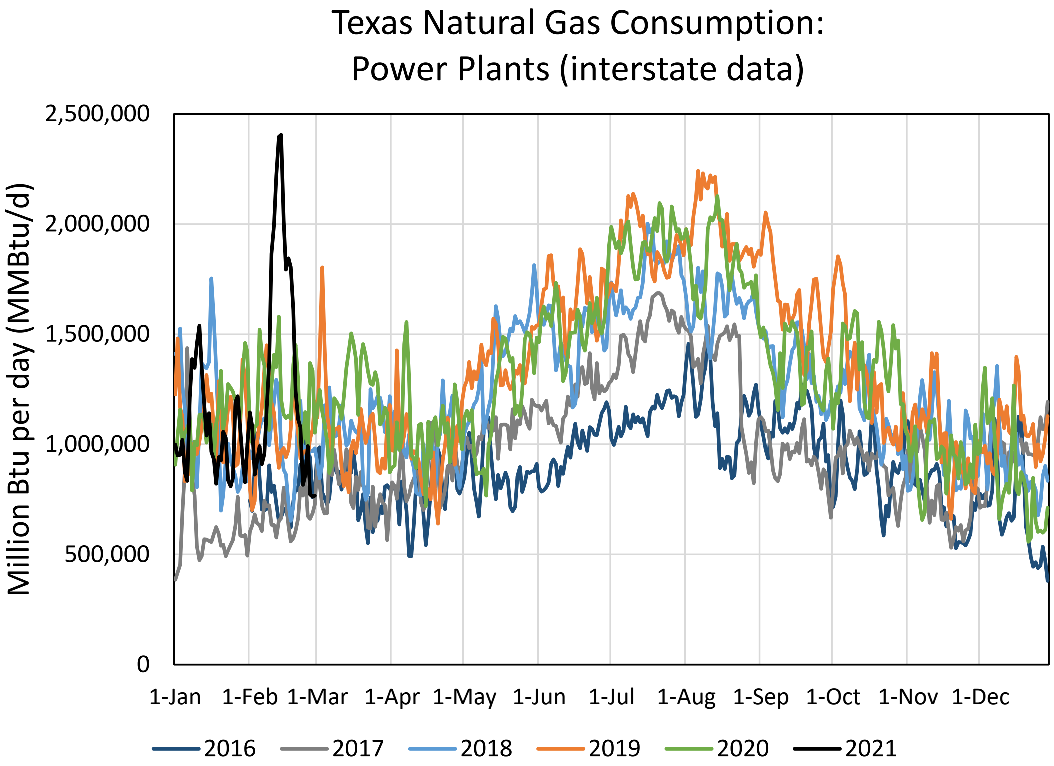

Figure 2.dd. Texas natural gas consumption by power plants via our sample of connection points to interstate pipelines. (Source: Wood Mackenzie)

2.6.4. Exports By Pipeline and Liquified Natural Gas (LNG)

Besides delivering gas to local consumers, power plants and industrial facilities, Texas exports natural gas to other states in the US and other countries including Mexico and those in Asia and Europe. To provide full context of the impacts of Winter Storm Uri on natural gas production, delivery, and consumption, we present data on the flow of natural gas out of Texas via pipeline and tanker.

Figure 2.ee shows the Texas natural gas flows by end users in Texas local markets (consumers, Electric Generation and Industrial) and exports via pipelines and liquified natural gas (LNG) ship cargos. One can observe the seasonal patterns of peaking pipeline exports and consumers demand (residential and commercial customers) in the winter with power plant consumption peaking in the summer months. In addition to the consumption within Texas and fuel losses, there has been 8-10 10 Bcfd (~10,000,000 MMBtu/d) of exports via pipelines and LNG cargos.

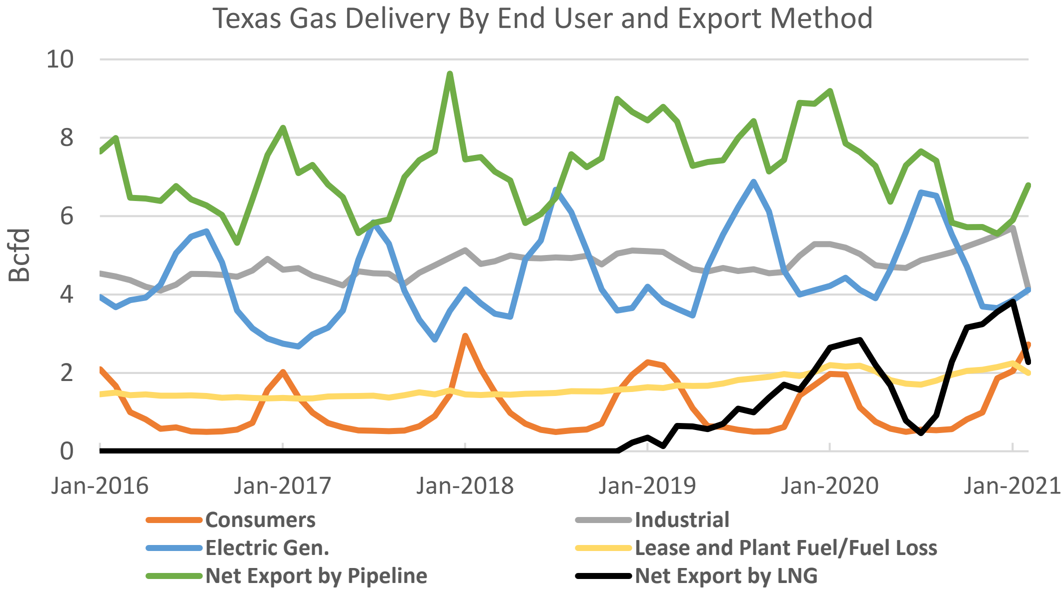

Figure 2.ee. Texas daily natural gas delivery (averaged each month) by end user (in Texas) and export method (pipeline and liquefied natural gas, or LNG, tanker). (Source: GPCMTM)

Pipeline exports from Texas reach the U.S. Northeast and East Coast markets via interstate pipelines that cross Texas' eastern state border. Pipeline exports to the midcontinent and west coast markets, including Mexico, Arizona and California, occur via pipelines that cross Texas' western border. Although many of these pipelines span a wide geographic range, it is fair to say that the exports from East and West Texas serve different downstream markets, with small exceptions.

2.6.5. Texas Pipeline Exports

Since 2016, during the month of February, Texas normally exports a net 6 Bcfd through its interstate pipelines. Figure 2.ff shows Texas pipeline net exports crossing the East and Texas West[92] border via interstate pipelines, since 2016.

Due to a lack of upstream supply, there is a reduction in both imports and exports starting in the second half of the week leading to the storm (see Figure 2.gg). During February 10-13, exports out of Texas dropped significantly below the previous five-year February minimum for the pipelines in the sample. Exports out of East Texas not only dropped to a historically low level, but also 5 out of 16 exporting pipelines reported reversed flow, declining from a net exports of average 2.8 Bcfd in February to net import of 0.3 Bcfd. For the west side, pipeline net exports dropped from 3.2

[92] There is small portion of gas exported from West Texas goes to Mexico through El Pas Gas Pipeline system. After the interconnection meter included for the Texas Export sample, there is one more meter downstream within the Texas border that measures flows to Mexico, and its flow averaged around 114,000 MMBtu/day since 2020. That exported volume can be seen in Figure 2.hh as reported data for the El Paso Natural Gas pipeline.

Bcfd in February to 0.6 Bcfd February 18, a drop of almost **95%** relative to the historical February average of 6 Bcfd.

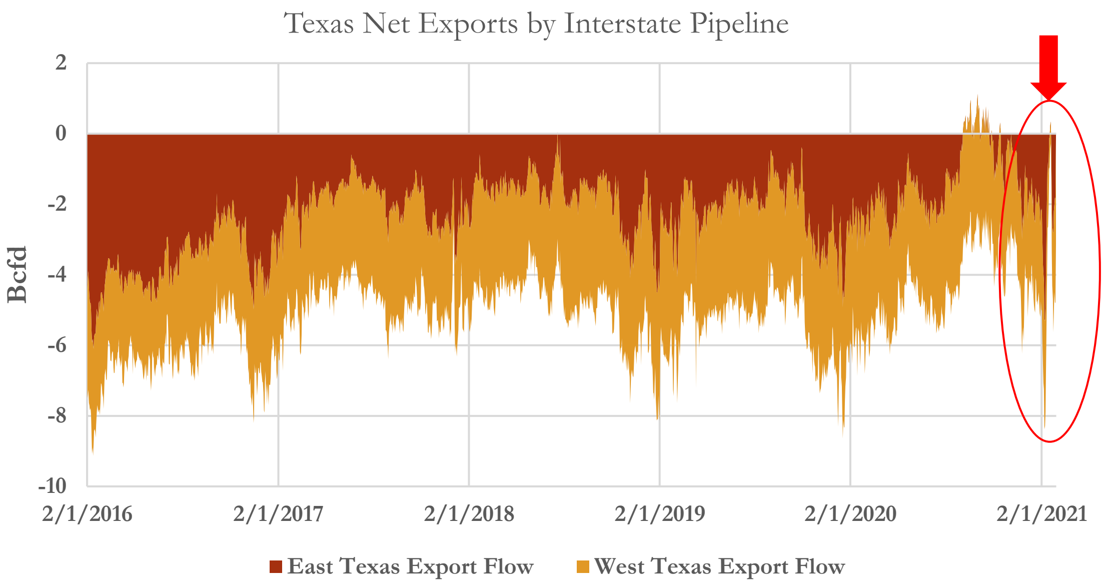

Figure 2.ff. Daily flow rates of Texas net exports of natural gas as in our sample of interstate pipelines crossing Texas' East and Western borders (2016 through February 2021). (Source: Wood Mackenzie)

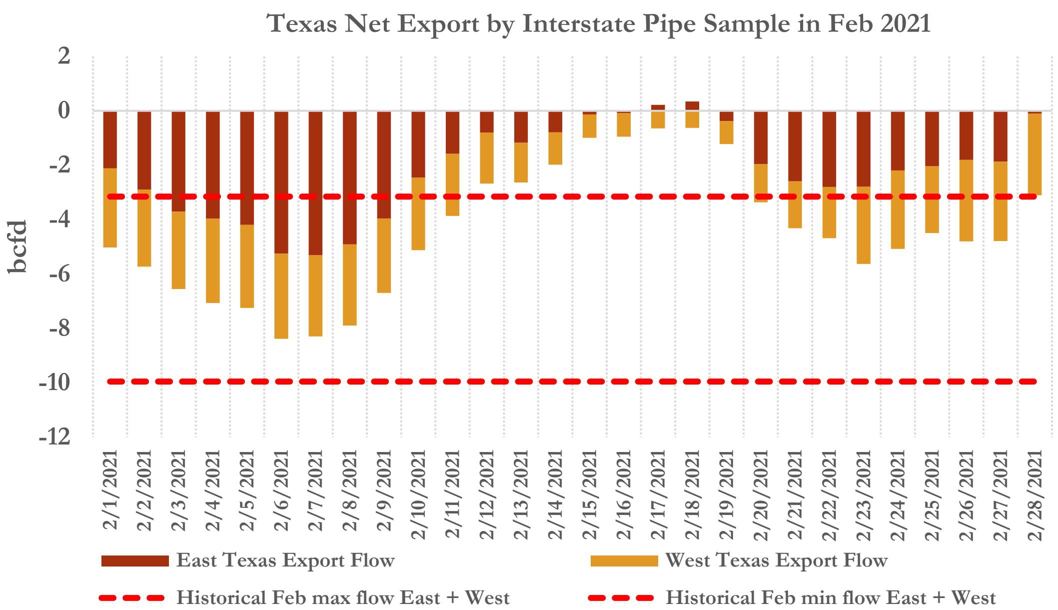

Figure 2.gg. Daily flow rates of Texas net exports of natural gas as in our sample of interstate pipelines crossing Texas' East and Western borders (February 2021). (Source: Wood Mackenzie)

Furthermore, Texas exports to Mexico have averaged around 5.3 Bcfd since January 2021, according to data from Wood Mackenzie. Figure 2.hh shows daily cross border flows, for February 2021 from Texas to Mexico, for a sample of five interstate pipelines that account for about 35% of the total Texas exports to Mexico. This figure shows that the lowest exports to Mexico occurred on February 16, during the middle of the ERCOT blackouts, at 40% below the exports on February 1.

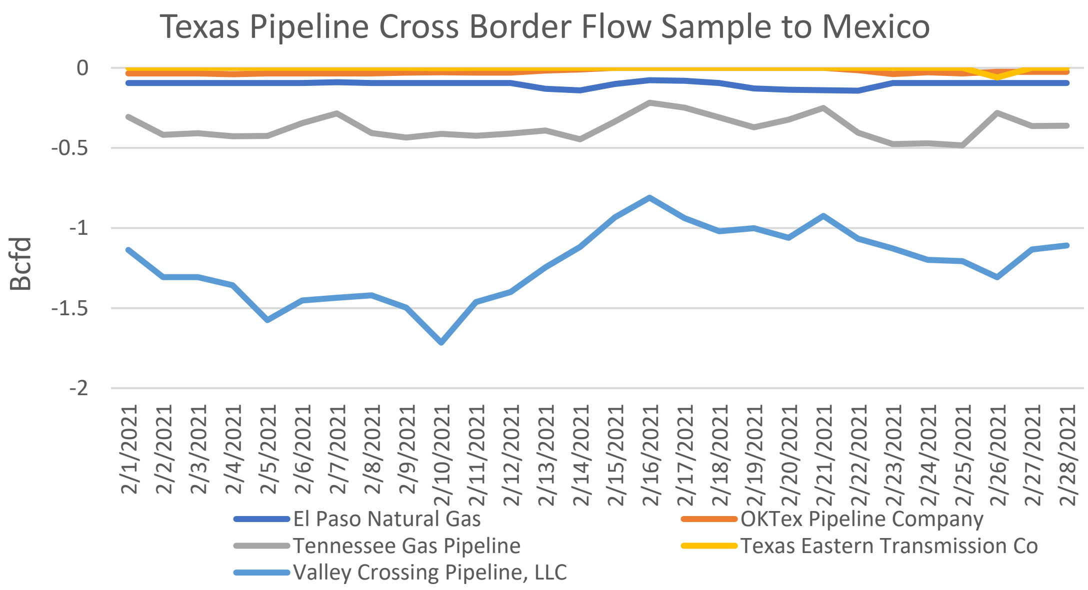

Figure 2.hh. Natural gas flow from Texas to Mexico via a sample of pipelines. (Source: Wood Mackenzie)

2.6.6. Texas LNG exports

The two main markets for U.S. liquified natural gas (LNG) exports are East Asia and Europe. For exported gas, the seasonality is determined by the demand of destination markets. There is a clear winter peaking pattern for LNG cargos with a longer winter (in Europe and Asia compared to Texas). Similar to pipeline exports, LNG exports also peak during the winter with significant heating demand in Europe and Asia. For example, in January, the month before the storm, U.S. LNG exports to China hit a new record high as East Asia was experiencing a winter that was colder than normal.

Texas exports LNG cargos from two existing LNG terminals in Corpus Christi and Freeport that have a total liquefaction capacity of 4.3 Bcfd (Figure 2.ii). Based on EIA reported data on Texas LNG exports, there was a drop in LNG exports of about 50% in February 2021 as compared to the previous month. During the winter storm, there was roughly a 25% drop of LNG cargo[93] sent out from the U.S. as a whole.

[93] EIA: U.S. Natural Gas Exports and Re-Exports by Point of Exit (https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm).

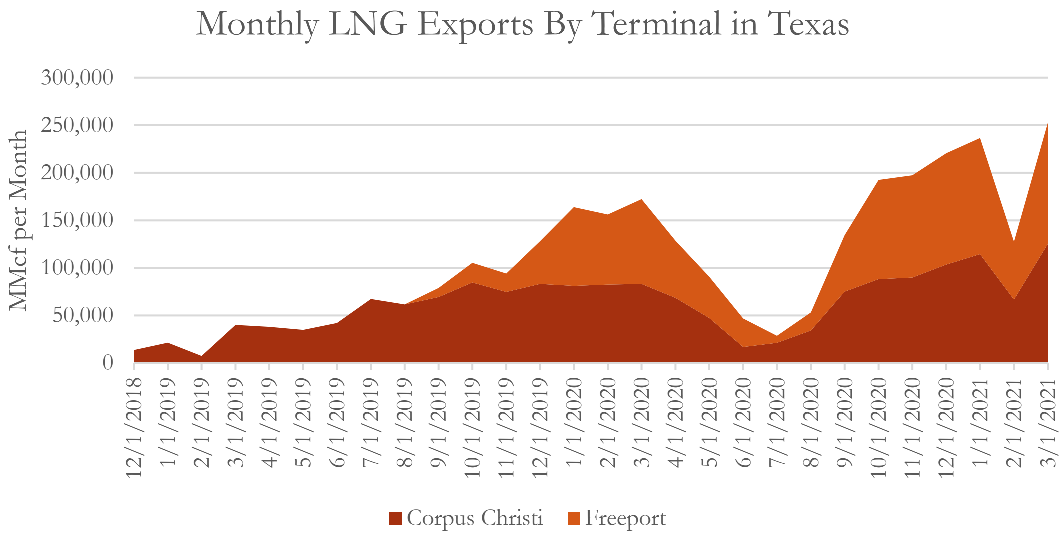

Figure 2.ii. Monthly LNG exports from Texas terminals. (Source: EIA)

2.6.7. Natural Gas Infrastructure Participation in Load Curtailment

Requests for Information (RFI) responses to ERCOT from Qualified Scheduling Entities (QSEs) indicated that approximately 67 locations (electrical meters) that were in ERCOT's ERS program were also in the fuel supply chain for generation resources, including gas refining and pipeline infrastructure. A separate set of data that compared the electric meter IDs of resources in the ERS program with those also registered as critical load with the major TDSPs indicated that 5 locations that self-identified as critical natural gas infrastructure were in the ERS program.[94]

Cross-referencing ERS participating loads in the municipal and cooperative utility regions of ERCOT identified a further 5 locations that, via satellite imagery overlaid with spatial natural gas pipeline data, appeared to also be associated with natural gas infrastructure.

It is possible that there is overlap in the RFI and TDSP datasets mentioned above, but nonetheless it does appear that some power plant fuel supply chain infrastructure, including some self-identified as critical, were participating in paid load reduction programs that would have turned them off when ERCOT deployed ERS resources.

[94] These ERS-participating locations only identified themselves as critical natural gas loads after they had been turned off by the TDSP.

3. Electricity and Natural Gas Financial Flows and Prices

This chapter recounts the economic and financial impacts of the event. Wholesale electricity prices during the event are reviewed, as well as decisions by the PUCT which affected those prices. Natural gas prices are also reviewed and the financial impacts of the price spikes in the state's electricity and natural gas industries are discussed.

3.1. Energy Prices

While the Texas electricity market structure is primarily an energy, not capacity, market,[95] it relies upon market price adjustments to help match supply and demand in real-time. These market price adjustments are the ERCOT Wholesale Electricity and Scarcity Pricing Real-time prices. They are calculated based on three categories: 1) supply and demand, 2) levels of available reserves, and 3) "out of market" reliability actions. During normal operations, prices are set by the offers of power plants, the level of demand, and any constraints[96] on the system. Over the past few years, prices during normal operations have averaged in the low tens of dollars per MWh.

When there is a risk that the supply may not be able to meet the demand, meaning there are low levels of reserves, Real-Time **Reserve** Price Adders are employed to increase electricity prices. These short-term price adders increase revenues to generators and while they are meant to incentivize investment in new generation sources, they also incentivize investment in other technologies, such as demand response. The value of the Real-Time **Reserve** Price Adders is based on the Operating Reserve Demand Curve (ORDC). Via the ORDC, once reserves fall below 2,300 MW, wholesale real time prices increase rapidly to the system-wide offer cap, currently $9,000/MWh.[97] These adders largely explain the rapid swings in real-time wholesale electricity prices, from values below $1,000/MWh to the cap, from February 12-15 (Figure 3.a).

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[95] An energy-based electricity market is one in which the production of energy (i.e., megawatt-hours, MWh) is compensated, but not the availability of capacity (i.e., MW), aside from the provision of ancillary services and resources involved in emergency response programs.

[96] Such as transmission constraints.

[97] It is possible for prices to go above $9,000/MWh if additional local constraints become binding.

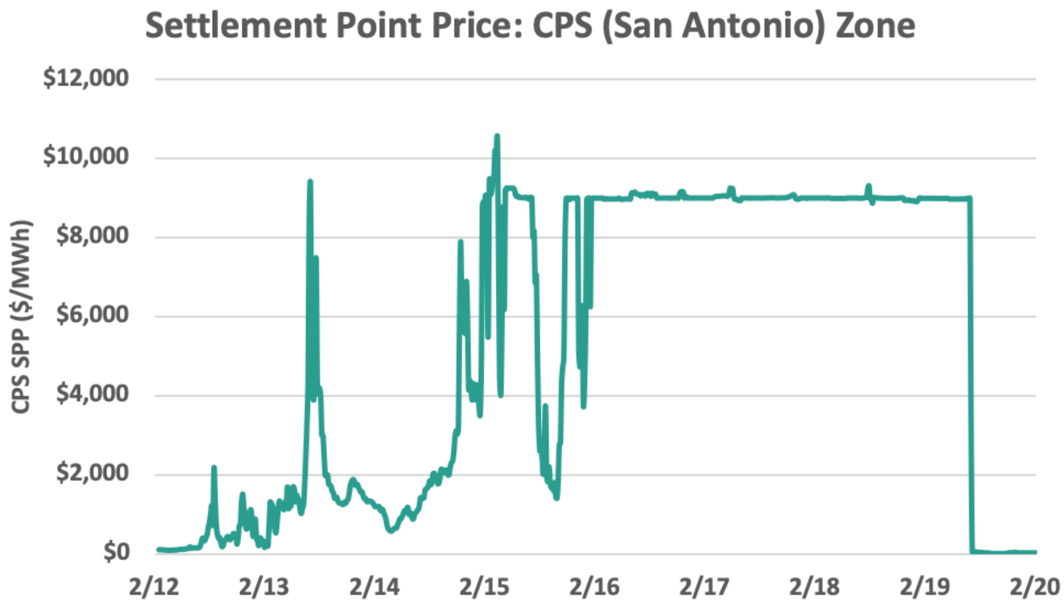

Figure 3.a. ERCOT real-time wholesale electricity prices during February 12-19, 2021 in the San Antonio Zone of ERCOT.

Real-Time **Reserve** Price Adders only include data from "in-market" conditions and do not inlcude "out-of-market" actions[98] that might impact in-market conditions. For example, if reserves drop too low and ERCOT goes into emergency operations and deploys Emergency Response Services (ERS), it may appear that reserves have increased (either via emergency generation brought online or responsive load taken offline). With a higher level of reserves, the value of the Real-Time **Reserve** Price Adders can decline even when scarcity in the market is still very high. To compensate for this possibility, another scarcity pricing mechanism, the Real-Time **On-Line Reliability Deployment** Price Adder (RTORDPA) was developed to keep real-time prices high when emergency actions have been taken.

While some forms of "out-of-market" actions are considered within the calculation of the Real-Time **On-Line Reliability Deployment** Price Adder, firm load shed is not.[99] According to current market protocols, if ERCOT initiates blackouts such that reserves appear high and recalls or cancels other out-of-market actions, price formation is once again based on supply and demand, even if demand is artificially lower due to active blackouts. This is why prices on February 15 were below $9,000/MWh for part of the day (Figure 3.a).

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[98] Such as ERS deployment and firm load shed.

[99] See http://www.ercot.com/mktrules/nprotocols/current, Section 6.5.7.3.1.

3.2. Ancillary Service Prices

The prices of ancillary services (AS)[100] reached new heights during the winter event. Prior to the storm, the prices of regulation up, responsive reserve service, and non-spinning reserves had never exceeded $4,999, $8,956, and $7,000 per MW, respectively. Due to extreme scarcity, pricing protocols drove AS costs (Figure 3.b) much higher than previous levels to $24,993, $25,674, and $12,867 per MW for regulation up, responsive reserve service, and non-spinning reserves, respectively. While the PUCT did take action during the winter event to specify wholesale energy prices outside of the established ERCOT market protocols (see following section describing PUCT orders during the blackout), it did not take similar action on AS prices. The Independent Market Monitor has argued that the prices for these services should have been capped at $9,000 per MW, consistent with the energy offer cap of $9,000 per MWh.[101]

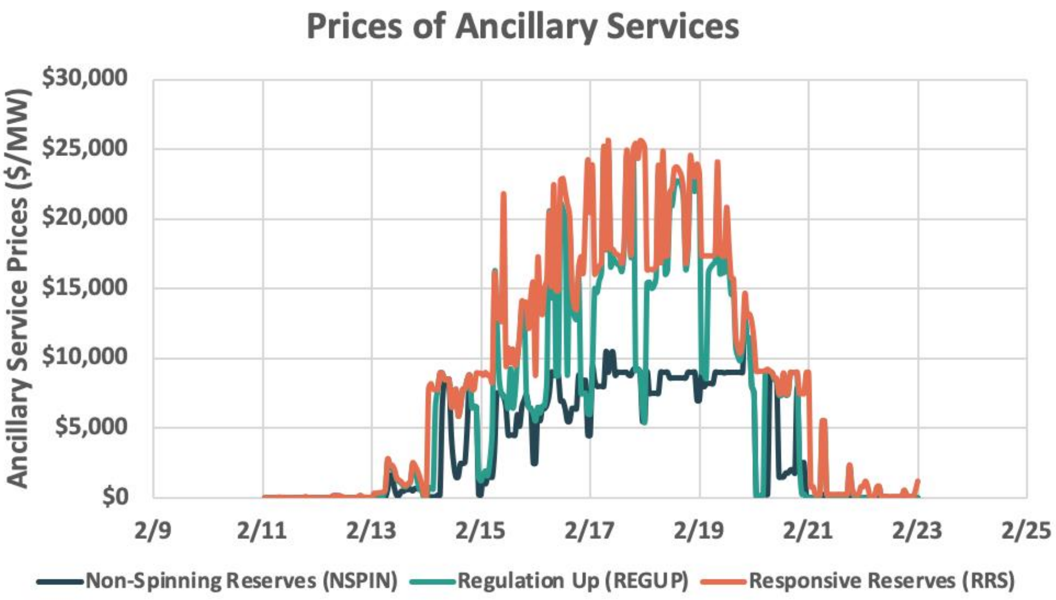

Figure 3.b. Prices of Ancillary Services from February 11, 2021 through February 22, 2021. Source: ERCOT

3.3. PUCT Orders During February Blackout

On Monday, February 15 ERCOT initiated load shed orders and found itself in an unprecedented situation with regard to solving for day-ahead market prices. It was unclear what the value of "demand" should be for the day-ahead scheduling algorithms when power had been cut off to a large percentage of customers. If

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[100] The US Federal Energy Regulatory Commission's Order 888 issued in 1996 defines AS as operating reserves (MW) "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

[101] http://interchange.puc.texas.gov/Documents/51812_34_1113309.PDF.

ERCOT assumed demand levels based upon the subset of customers that were connected to the grid, then there would be enough generation to meet that demand, and prices would not reflect the level of scarcity in the market. In cases of generation scarcity, the PUCT's scarcity pricing mechanism is designed to increase wholesale prices to the applicable maximum price levels, the system-wide offer cap.[102] During the grid emergency, the PUCT attempted to impose real-time corrections to the market structure to handle this singular event.

3.3.1. Electricity Market Price Changes/Corrections During the Event

During the February freeze events, the PUCT issued two orders under Project 51617 that impacted ERCOT electricity market pricing. The first order[103] determined that prices during the load shedding that began on February 15, 2021 were not reflective of scarcity in the market, because prices were clearing below the system-wide offer cap of $9,000/MWh.[104] The Commission asserted that this outcome was inconsistent with the fundamental design of the ERCOT market. Energy prices should reflect scarcity of the supply. If customer load is being shed, scarcity is at its maximum, and the market price for the energy needed to serve that load should also be at its highest.[105]

The order goes on to instruct ERCOT to "ensure that firm load that is being shed in EEA3[106] is accounted for in ERCOT's scarcity pricing signals." This instruction resulted in setting ERCOT market prices to $9,000/MWh while load shedding was happening. The first order under Project 51617, issued on February 15, 2021, also retroactively raised prices in the market to the market cap of $9,000/MWh if they had been below that value between the period of time that load shed began and the order was

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[102] The system wide offer cap can be set at two different levels, depending on the amount of peaker net margin experienced in the market so far in a given year: the High System-Wide Offer Cap (HCAP) or Low System-Wide Offer Cap (LCAP). See Texas Administrative Code Chapter 25: SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS, Section 25.505 with discussion of Scarcity Pricing Mechanism: http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf.

[103] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[104] The system-wide offer cap in ERCOT is administratively set at $9,000/MWh, also known as the High System-Wide Offer Cap (HCAP), until peaker net margin is reached at which time protocols direct to drop to the Low System-Wide Offer Cap (LCAP) which is *the greater of* either 1) $2,000 per MWh or 2) 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour. The natural gas price index value is the previous daily average price of natural gas as indexed in the Katy Hub (NPRR 952).

[105] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[106] Energy Emergency Alert Level 3 (EEA3) is the highest level of emergency conditions at ERCOT and is the point when ERCOT is allowed to order firm load shed, i.e. instruct Transmission Operators to initiate blackouts.

issued. A secondary order[107] under the same project, issued on February 16, 2021, cancelled the retroactively raised prices section of the first order.

The second part of the February 16, 2021 order suspended the system-wide offer cap price calculation mechanism for LCAP that would have come into effect when the system reached the Peaker Net Margin (PNM).[108] The PNM value increases based on the amount of scarcity pricing seen in the ERCOT market, and it is cumulatively calculated starting from a value of $0 on January 1 of each year. The PNM threshold, defined as $315,000/MW-yr, is based on triple the Cost of New Entry (CONE) for a new peaker power plant to enter the ERCOT market. When the PNM value exceeds $315,000/MW-yr, the system-wide offer cap is supposed to change from the HCAP to the LCAP. ERCOT reports the current Peaker Net Margin levels as of 4:00 pm every day. Figure 3.c shows the PNM values throughout the storm. PNM never met its threshold before 2021, but, by the end of the week of February 15, 2021 reached a value more than double the threshold.

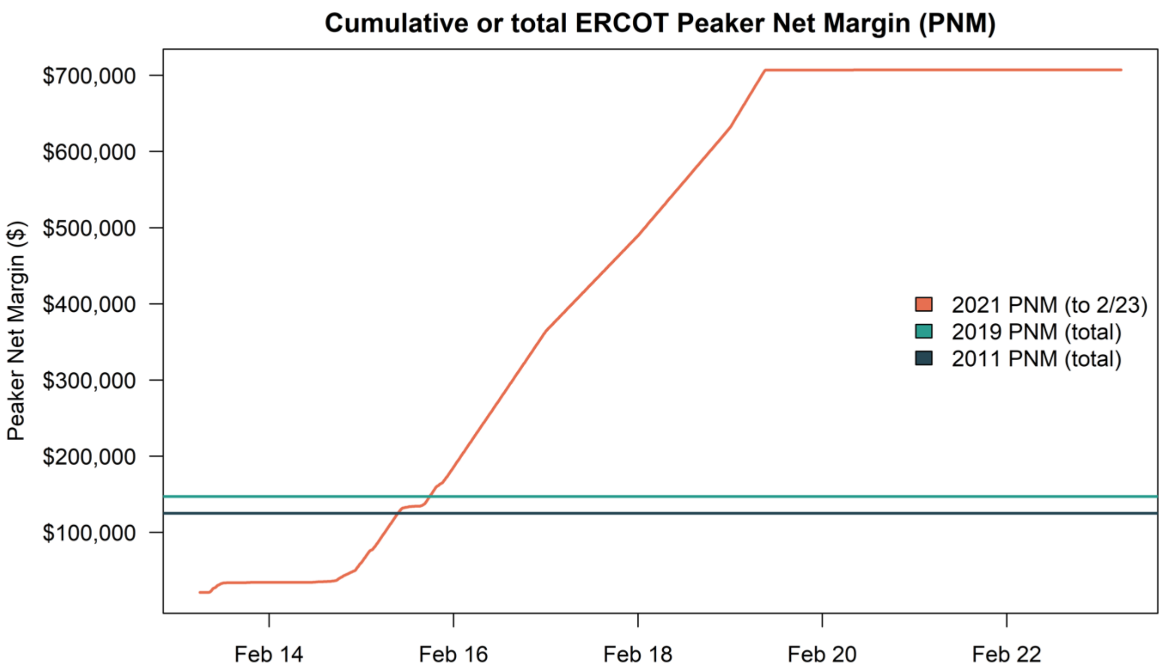

Figure 3.c. The Peaker Net Margin (PNM) for February 14-22, 2021 compared to the total value of PNM reached by the end of the years 2011 and 2019.

Once the PNM is reached in ERCOT, the wholesale price cap changes from HCAP to LCAP. When LCAP and HCAP were defined, it was assumed that LCAP would always be lower than HCAP. However, on February 16, the PUCT stated that it was

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107 https://www.puc.texas.gov/51617WinterERCOTOrder.pdf.

108 The PNM is used to approximate the amount of profit or margin that a new natural gas-fired power plant might be able to earn, based on the cost of building a new plant, natural gas prices, and the efficiency of a new natural gas-fired power plant.

concerned that the formula for LCAP would actually translate to a higher price than the HCAP price of $9,000/MWh. The PUCT's order in Docket No. 51617 states:

> *[T]he peaker net margin (PNM) threshold [is] established in 16 TAC § 25.505(g)(6). That threshold is currently $315,000/MW-year. As provided in §25.505(g)(6)(D), once the PNM threshold is achieved, the system-wide offer cap is set at the low system-wide offer cap (LCAP), which is "the greater of" either "(i) $2,000 per MWh and $2,000 per MW per hour; or (ii) 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour." Due to exceptionally high natural gas prices at this time, if the LCAP is calculated as "50 times the natural gas price index value," it may exceed the high system-wide offer cap (HCAP) of $9,000 per MWh and $9,000 per MW per hour. 16 TAC § 25.505(g)(6).*[109]

Because of the extreme demand for natural gas and constraints in natural gas supply, the price of natural gas was also much higher than normal during the February event. At one point, daily gas price averages at the LCAP-indexed hub were trading near $400/MMBTU.[110] Tom Hancock, COO of Garland Power and Light, testified that he received a quote for natural gas at $1,100/MMBtu.[111]

If the PUC had not ordered the suspension of the HCAP to LCAP transition, ERCOT would have been required to release a market notice on February 17 notifying the market that PNM had been reached on February 16 and that LCAP would have come into effect on February 18. If the LCAP had been allowed to come into effect, the LCAP calculation would have driven the market price higher than the HCAP on February 18 to $15,359/MWh. The LCAP on February 19 would have been $3,318/MWh. By February 20 the Fuel Index Price was low enough that the LCAP dropped down to $2,000/MWh.[112]

Table 3.a shows what the values for LCAP would have been if the PUCT had not suspended it.[113]

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[109] http://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[110] MMBTU = million British Thermal Units

[111] February 25 and 26, 2021, Joint Hearing: State Affairs and Energy Resources Part 1 and Part 2, https://house.texas.gov/video-audio/committee-broadcasts/87/.

[112] The LCAP is the greater of either $2,000 per MW per hour, or 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour. This calculation assumes that the PUCT would have still have forced the market price to the system wide offer cap, but would have left the LCAP in place.

[113] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

Table 3.a. Calculation of what LCAP would have been if not for the PUCT orders.[114]

Date	LCAP ($/MWh)
2021-02-18	$15,359.00
2021-02-19	$3,318.00
2021-02-20	$2,000.00

Figure 3.d shows ERCOT market prices from February 14 to the end of February 19 without the LCAP (i.e., what actually happened) and if the LCAP had been allowed to come into effect as per protocols.[115]

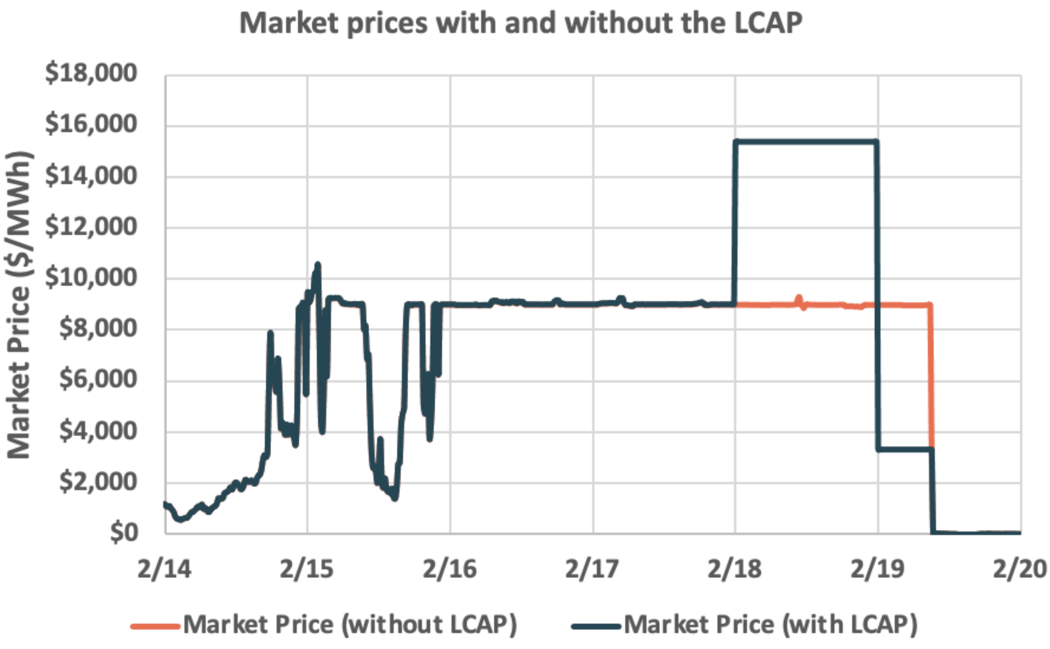

Figure 3.d. Approximate market prices with and without the LCAP (data used to calculate the LCAP provided by ERCOT).[116]

Because Peaker Net Margin was achieved on February 16, as per the ERCOT protocols, LCAP would have come into effect on February 18. On February 18, market prices would have increased from approximately $9,000/MWh (the HCAP) to $15,359/MWh. For the hours of scarcity pricing on February 19, the LCAP would have reduced prices from $9,000/MWh to $3,318/MWh. Given that the LCAP would have been approximately $6,360/MWh higher than the HCAP for the entire day on February 18, and about $5,680/MWh lower for only a short period of time on

[114] LCAP values were calculated based on the Fuel Index Price data provided by ERCOT.

[115] We make the assumption that scarcity pricing would have ended at the same time as it did in reality.

[116] These estimated prices are just the LCAP System Wide Offer Cap (SWOC) and do not include any estimate of system dynamics that, in reality, can push prices higher than the SWOC.

February 19, the overall energy costs for that week would have been approximately $5.2 billion dollars higher (Figure 3.e), or about 11% more absent action by the PUCT.

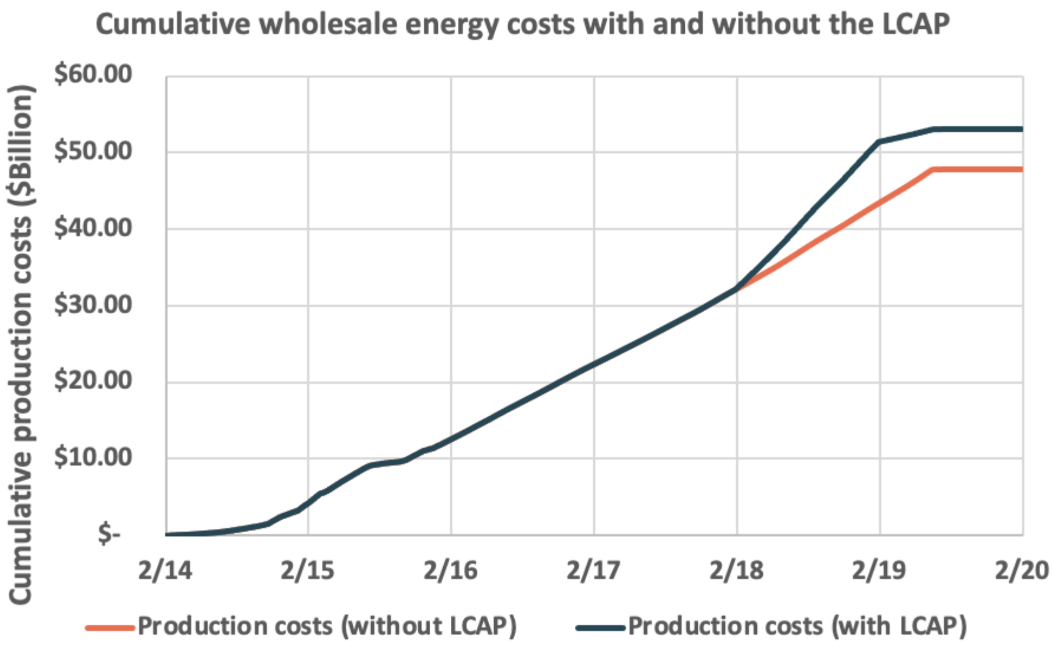

Figure 3.e. Cumulative wholesale energy costs with and without the LCAP.

Figure 3.e shows the difference in cumulative market energy costs with and without the LCAP.[117] Because the LCAP would not have come into effect until February 18, energy costs are the same for both sets of market prices until then.

3.4. Financial Fallout

Regulators and policy makers have very limited information about contracts and hedging relationships among participants in the State's electricity and natural gas industries. This is particularly true for financial transactions negotiated outside of ERCOT's formal day-ahead and real-time markets for energy and ancillary services. Such information is generally regarded as confidential. Thus, when faced with the decisions regarding whether to raise prices to attract more supply and encourage price-sensitive loads to reduce demand, or whether to "re-price" energy transacted through ERCOT's markets, the PUCT Commissioners stated that they were unable to determine which market participants might benefit or be disadvantaged by such actions.[118]

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[117] These values are calculated by multiplying the load times the price with and without the LCAP as shown in Figure 3.d. While much energy in ERCOT is transacted in the Day-Ahead Market (DAM), it is not known how different relative DAM prices would have been had LCAP not been suspended. Thus, while the absolute numbers might be different, the percentage increase might be similar.

[118] See PUCT Open Meeting of March 5, 2021, item 22: http://www.adminmonitor.com/tx/puct/open_meeting/20210305/.

On April 14, 2021, ERCOT reported cumulative aggregate "short payments" of approximately $2.9 billion, and that it would take 96 years to collect the amount outstanding using its standard Default Uplift Invoice process.[119] This estimate was raised to $2.99 billion on May 14, 2021.[120] Of that, $1.86 billion relates to the default of Brazos Electric Power Cooperative Inc., which filed for bankruptcy on March 1, 2021. Other market participants that had failed to pay amounts owed to ERCOT at that time included Rayburn Country Electric Cooperative, Eagles View Partners LTD, Energy Monger LLC, Entrust Energy Inc., GBPower, Griddy Energy LLC, Gridplus Texas Inc., Hanwha Energy USA Holdings Corp., Iluminar Energy LLC, MQE LLC, Power of Texas Holdings Inc., and Volt Electricity Provider LP. As a consequence of receiving less revenue than ERCOT has invoiced to the market, ERCOT has reduced payments to market participants that are owed revenues from the market for congestion revenue rights.[121]

Under present market rules, unpaid amounts are uplifted to all market participants based on each market participant's MWh activity (energy bought or sold through ERCOT's formal markets) in the month prior to the defaulted payment.[122] However, these uplift mechanisms are limited to $2.5 million per 30 days.

The financial impacts on electricity retailers depend upon the degree to which their price risk was hedged and how service outages affected their obligations to provide energy during the event. Griddy Energy LLC, Entrust Energy Inc., and Power of Texas Holdings Inc. have each filed for bankruptcy.[123,124,125] Their certificates to serve customers in the ERCOT market were revoked, and their customers were moved to other retailers through ERCOT's "mass transition event" process. The customer bases of GridPlus MQE LLC (My Quest Energy), GB Power, Volt Electricity Provider LP, Energy Monger, and Iluminar Energy were acquired by JP Energy Resources, while the customer bases of Entrust Energy Inc. and Power of Texas Holdings Inc. were acquired by Rhythm.[126] Just Energy Group – using the brand names Amigo Energy, Filter Group Inc., Hudson Energy, Interactive Energy Group, Tara Energy, and

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[119] Electric Reliability Council of Texas, Inc.'s notice of planned implementation of default uplift invoice process. PUCT Project No. 51812: Issues related to the state of disaster for the February 2021 winter weather event.

[120] ERCOT Market Notice M-A051421-01, May 14, 2021. M-A051421-01 Estimated Cumulative Aggregate Short Pay Amount (ercot.com)

[121] http://www.ercot.com/services/comm/mkt_notices/archives/5377.

[122] http://www.ercot.com/content/wcm/lists/226521/Senate_Jurisprudence_031021_FINAL.pdf.

[123] https://www.bizjournals.com/houston/news/2021/04/01/entrust-energy-bankruptcy-behind-the-deal.html.

[124] https://www.cbsnews.com/news/griddy-energy-texas-files-bankruptcy/

[125] https://www.bankruptcyobserver.com/bankruptcy-case/POWER-OF-TEXAS-HOLDINGS.

[126] https://www.prnewswire.com/news-releases/rhythm-acquires-customers-of-entrust-energy-inc-and-power-of-texas-holding-inc-301241112.html.

terrapass – also filed for bankruptcy after sustaining an estimated $250 million loss.[127]

Media reports provide some insights into how the event impacted the financial standing of some market participants. However, we emphasize that our Committee is unable to audit, verify, and affirm any of the financial information repeated here.

NRG, the largest retailer in terms of market share in ERCOT,[128] reported a negative impact of $500 million to $700 million.[129] The second-largest retailer, Vistra, expects its financial losses due to the storm to be around $2 billion.[130] Both NRG and Vistra own and operate power plants, in addition to serving retail customers.

The impacts on municipal utility systems were mixed. The state's largest municipal electric and natural gas provider, CPS Energy reported losses on natural gas fuel purchases of between $675 and $850 million, and losses on purchased power costs in the range of $175 million to $250 million.[131] In contrast, Austin Energy may have benefited by about $54 million.[132] The Brownsville Public Utility Board has estimated a shortfall of $32.1 million.[133]

Generation owners whose fleets of generation resources operated well and were able to provide generation that met or exceeded their commitments[134] were generally not financially harmed, and could have profited if a generator was able to provide generation that met or exceeded its obligations. Many generators, however, have locked-in a price for their generation through a contract or exchange, thus limiting its profit potential. If the generation owner is dependent upon natural gas as

[127] Gold. R. (2021). Texas Power Market Is Short $2.1 Billion in Payments After Freeze; Electric retailers failed to make payments for power purchased when prices skyrocketed during the freeze, state grid operator says. The Wall Street Journal. Feb. 27.

[128] https://www.sciencedirect.com/science/article/abs/pii/S1040619020301408.

[129] Bank of America Global Research, NRG Energy, Uri Impacts Unpacked: More Constructive Backdrop than Thought. May 6, 2021. NRG Energy, Inc. Financial Update on Winter Storm Uri Impacts: https://finance.yahoo.com/news/nrg-energy-inc-financial-winter-100100947.html.

[130] Bank of America, VST US: Uri Impacts More Complicated Than We Thought. April 27, 2021.

[131] https://newsroom.cpsenergy.com/cps-energy-will-be-taking-decisive-action-to-protect-customers-and-the-san-antonio-community-from-price-gouging-for-illegitimate-fuel-power-costs/.

[132] https://emma.msrb.org/P21441577-P21119174-P21530470.pdf.

[133] https://www.yahoo.com/now/brownsville-public-utilities-board-tx-000816313.html?guccounter=1&guce_referrer=aHR0cHM6Ly93d3cuZ29vZ2xlLmNvbS8&guce_referrer_sig=AQAAAKwSPg3ZndRfIqbgkl2hbe9Bp-QR7-qBQeINCXN5DbGZX7ha6if6FgC-zfj-MH4C8Cm4VEnmEnbXQuLSN_vGRLS5rD4CHQS6omLbqtR2gU4g-EFOI257SWf4vyv_mw1ffecwHj5Y91c-FAtrHN9PwiZ-bVT_v-uZtmDHctJ62UOK.

[134] A commitment might result from the sale of energy through a purchased power agreement (PPA), some other out-of-market bilateral contract between a generator and a counterparty, the sale of generation through a non-ERCOT market such as the Intercontinental Exchange (ICE), or an award in ERCOT's formal day-ahead market.

a fuel and the owner had exposure to the high natural gas spot prices, the net impacts would be unclear without more detailed information.

A generation owner whose fleet of generation assets failed to perform well is likely to have experienced a negative financial impact. To meet obligations through ERCOT's formal markets, such an entity may have been required to buy replacement energy at a price as high as $9,000 per MWh (or higher). It has been reported that the state's four largest power producers – Vistra, Excelon Corp., NRG Energy Inc., and Calpine — collectively lost between $2.5 billion and $4 billion due to power plant performance problems, high natural gas prices, fuel supply constraints, and other problems.[135]

Many owners of wind generation projects that failed to perform reported deep financial losses.[136,137,138,139,140] Wind generation owners often receive revenue through financial hedges. Wholesale market prices in excess of contract prices and/or wind generation below contracted quantities may trigger a payment to a counter-party (often a financial institution). This has prompted at least one lawsuit by a wind farm against a financial institution, seeking to avoid payments.[141]

Owners of natural gas-fueled power plants with performance below expectations reported losses, including Exelon.[142]

Natural gas suppliers able to produce and transport natural gas to a market for a sale based on the spot price profited during the winter week. Natural gas producers reporting large gains due to the storm include Antero Resources Corp.,[143] Comstock

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[135] Blunt, K, Gold, R. (2021) A Texas-Sized Problem: Overhauling the Power Market --- The February storm exposed flaws in the state's hands-off approach to electricity. But changes promise to be complex and costly as lawmakers try to balance reliability and pricing. The Wall Street Journal. April 17, 2021

[136] https://www.windpowermonthly.com/article/1707858/texas-blackouts-hit-rwe-renewables-profits.

[137] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/innergex-expects-up-to-c-60m-financial-hit-from-texas-storms-outages-62715363.

[138] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/rwe-takes-material-earnings-hit-from-texas-freeze-as-impact-on-europeans-emerges-62756391.

[139] https://www.globenewswire.com/news-release/2021/02/24/2181893/0/en/Clearway-Provides-Update-Regarding-Recent-Texas-Weather-Events.html.

[140] https://www.windpowermonthly.com/article/1715644/texas-freeze-lower-european-winds-hit-rwe-q1.

[141] https://www.kltv.com/2021/03/12/lawsuit-claims-tx-panhandle-wind-farm-not-financially-responsible-after-winter-storm-causes-frozen-turbines/.

[142] https://www.bloomberg.com/news/articles/2021-02-24/exelon-sees-profit-cut-by-up-to-710-million-from-texas-cold.

[143] https://seekingalpha.com/article/4413442-antero-resources-growth-bug-bites-again.

Resources Inc.,[144] and Macquiarie Group.[145,146] Energy Transfer expects a $2.4 billion gain,[147] and BP reportedly made over $1 billion.[148] Kinder Morgan, an owner and operator of natural gas pipelines, terminals and storage, announced a $1 billion windfall profit from gas sales during the storm.[149] Yet a gas supplier unable to produce and transport gas, or who was involved in a hedging contract might have not been so fortunate.

Natural gas local distribution companies (LDCs) generally "pass-through" the commodity price of gas to ratepayers, such that LDCs' profits do not change based on wholesale gas prices. To soften the impact on ratepayers, the pass-through of high costs due to a price spike may be achieved over some extended period of time and securitization might be used to reduce debt carrying costs to the benefit of utilities and their consumers.[150] Some LDCs, including Atmos Energy, have reported challenges in financing the purchase of gas for resale to their customers during and following the winter event in light of the high prices and extended cost recovery period.[151] Some LDCs also anticipate high billing arrearages, as retail natural gas customers face utility bills with higher prices for the natural gas commodity.[152]

Various financial institutions (e.g., banks and financial trading companies) provide financing and hedges to participants in ERCOT's markets. The impacts upon companies in this sector will vary, depending upon the performance of their clients, the financial viability of their clients, and contractual terms and conditions. There

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144 https://theintercept.com/2021/02/23/texas-winter-storm-gas-prices-executives/.

145 https://www.afr.com/companies/financial-services/macquarie-jacks-up-profits-on-texas-big-freeze-20210222-p574jo.

146 https://www.reuters.com/article/us-macquarie-group-outlook/australias-macquarie-reaps-windfall-profits-from-u-s-winter-freeze-idUSKBN2AM01O.

147 https://www.bloomberg.com/news/articles/2021-05-06/energy-transfer-made-2-4-billion-gain-from-texas-winter-storm.

148 https://www.houstonchronicle.com/business/energy/article/BP-likely-made-at-least-1B-during-Texas-power-16133739.php; https://www.rigzone.com/news/wire/bp_execs_coy_about_texas_freeze_impact_on_gas_trading-27-apr-2021-165272-article/.

149 Gerson Freitas, Kinder Morgan Posts Blowout Profit on Texas Winter Storm, Bloomberg. April 22, 202; Harry Weber, Kinder Morgan gets big first-quarter lift from gas price volatility due to Texas freeze. S&P Global Platts, April 21, 2021.

150 Bank of America Global Research (2021). GAS LDC 1Q21EPS preview: The day after the storm; measuring the Feb URI. April 19, 2021. See also, HB1520 which passed in the Texas House on April 20, 2021.

151 https://www.reuters.com/article/us-usa-weather-texas-winners-factbox/factbox-winners-and-losers-in-energy-sector-from-texas-cold-snap-idUSKBN2AQ260.

152 https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-face-unprecedented-test-in-digesting-astronomical-storm-costs-62961274.

have been media reports suggesting windfall profits for firms in this sector,[153,154] though we have not been able to independently confirm these claims.

The near-term financial impacts on retail customers are dependent upon their agreements with retail electric providers or other load-serving entities (e.g., rural electric cooperatives and municipal utility systems). The vast majority of residential energy consumers in areas of the state opened to retail competition buy electricity under fixed-price rate plans and may see little impact on their electricity costs in the near-term. Residential customers on variable pricing plans may have received unusually high electric bills, as widely reported in the media. Over time, an increase in wholesale electricity prices tends to get partially passed-through to the prices quoted in new or renewed retail electricity offers from retailers (Hartley et al., 2019, Brown et al., 2020).

[153] Chung, J, Blunt, K. (2021). Texas Storm is a Windfall for some Wall Street Firms. The Wall Street Journal. April.

[154] Meyer, G., Noonan, L., Bank of America reaps trading windfall during Texas blackouts, Financial Times, March 5, 2021, at: https://www.ft.com/content/321c4fb2-ca11-4e15-9ef5-05598dd04012.

4. A Comparison to Winter Events in 2011 and 1989

It is instructive to compare the electricity industry's performance during the February deep freeze to the two earlier winter events which led to electrical outages in the ERCOT grid:

- December 1989
- Early February of 2011.

4.1. December 1989 Winter Event

During December 21-23, 1989, the weather was similarly cold as compared to mid-February of 2021. The low temperature in Austin was the same during both events. The low in Dallas was just 1°F colder in 2021 than in 1989. Houston reached a low temperature of 7°F during the 1989 winter event, or 6°F lower than the low temperature reached in Houston in 2021.

However, the electricity industry in Texas was far different in 1989. It was dominated by vertically-integrated electric utilities in 1989, and there was little market-wide control over operations.

Months before the 1989 winter event, the PUCT staff warned of reliability concerns associated with ERCOT's high reliance on natural gas for electricity generation, which represented 53% of the generation mix in 1989.[155]

> *Dependence on natural gas in the ERCOT generation mix (almost three times the national dependence) represents some reliability concern. … if severe winter conditions were to occur, there could be curtailment of gas supply for generating units. If such curtailment does occur and it becomes necessary to substitute fuel oil for gas, the rated capability of some units will be reduced due to equipment design, pipeline delivery constraints and/or oil inventories.*[156]

During the December 1989 winter storm, demand for electricity increased, along with the demand for natural gas for space heating. Weather-related equipment problems caused generating units to go offline. Power plant outages were traced to frozen instruments, frozen valves, boiler tube leaks, frozen batteries, and fish plugging cooling water intakes. Consistent with the concerns expressed by the PUCT staff earlier in the year, natural gas flows were curtailed by Lone Star Gas to the

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[155] Public Utility Commission of Texas, Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988, Volume I: Summary of Results and Recommendations, Feb. 1989, p. 6.6.

[156] Public Utility Commission of Texas, Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988, Volume I: Summary of Results and Recommendations, Feb. 1989, p. 6.7.

utilities in North Texas in early hours of December 21st, and many utilities serving South Texas lost their natural gas supplies the following morning. There was firm load shed of 1,710 MW (4.5% of peak load) on December 23rd, 1989. “Rolling” blackouts were achieved, lasting less than 10 hours for any given region, and different regions of ERCOT experienced different durations of outages. System frequency remained above 59.65 Hz throughout the event. At the time, the 1990 PUCT report on the 1989 winter event stated that “The combination of heavy demand and loss of generating units caused near loss of the entire ERCOT electric grid.[157] We now know the generator outages and blackouts were far smaller in magnitude than the outages in February 2021.

The financial impacts of the December 1989 event were quite modest in contrast to later events. Natural gas prices remained fairly stable in December 1989, as did retail electricity prices. The PUCT reviewed the costs incurred by the utilities under its jurisdiction and approved recovery of those costs determined to be reasonable and necessary and prudently-incurred. The utilities reported that corrective actions would involve costs of less than $3 million (which did not include costs that might be incurred by non-utility generators).[158]

4.2. February 2011 Winter Event

During the first week of February 2011, unusually cold and windy weather prevailed over the southwest U.S. While the weather was not as severe as during the winter events in 1989 and 2021, it nonetheless triggered similar problems. The FERC 2011 summary report of the winter event noted a total of 210 individual generating units in ERCOT experienced either an outage, a derate, or a failure to start, leading to a controlled load shed of 4,000 MW, affecting 3.2 million customers (FERC, 2011).[159] The FERC 2011 summary report also noted “... 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW” that was not a simultaneous outage in capacity and a peak of 14,702 MW in “... generation offline from such trips, derates, or failures to start.” Thus, approximately one-third of ERCOT’s total generation fleet was unavailable at the lowest point of the event.[160] Generation loss involved units of all ages and multiple types of fuel.[161] The Texas

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[157] Public Utility Commission of Texas, Electric Division Evaluation Report, Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989, November 1990.

[158] Electric Division Evaluation Report, Electric Utility Response to the Winter Freeze, Public Utility Commission of Texas, November 1990.

[159] FERC/NERC (2011), p. 1.

[160] FERC/NERC (2011), p. 7.

[161] Trip Doggett, ERCOT CEO (2011), ERCOT Presentation to Joint Senate Committees, February 2, 2011 Grid Emergency Events. February. Slide 10. http://www.ercot.com/content/news/presentations/2011/Senate_EEA_Presentationfinaltg.pdf

Reliability Entity (TRE) report on the same blackout noted "... a total of 225 individual generator units experienced a unit trip, a unit de-rate, or a failure to start …" resulting "... in a maximum of 14,855 Megawatts (MW) of unplanned unavailable capacity during the period. These generation issues, combined with pre-scheduled generation outages of 12,413 MW, created a significant generation capacity shortfall in the ERCOT Region." (TRE, 2011) We do not have an explanation for these variations in the number of generator outages within the FERC report and between the FERC and TRE reports, but they are within about 30 generation units. Both FERC and TRE noted very similar forced outages and derates of 14,702 MW and 14,855 MW, respectively.

On February 2, 2011, wholesale market prices reached the offer cap, which had recently been increased to $3,000 per MWh. The EEA Level 3 lasted from 5:43 a.m. to 2:01 p.m. on that day.[162] Frequency remained above 59.5 Hz throughout the event.[163]

The natural gas system could not meet demand. The production losses stemmed principally from freeze-offs, icy roads, and electric outages to the equipment used in the natural gas industry. Electric blackouts called by ERCOT and implemented by the TDSPs along with customer electrical curtailments for other reasons caused or contributed to 29% of the natural gas production outages in the Permian basin and 37% of the natural gas production outages in the Fort Worth basin.[164] These outages prevented the operation of electric pumping units and compressors on gas gathering lines.

The FERC/NERC inquiry into the 2011 events concluded that gas shortages were not a significant cause of the electric generator problems during that event, nor were rolling electrical blackouts a primary cause of the production declines at the wellhead. Nonetheless, this gas and electric interdependency was a contributing factor.[165]

In response to the 2011 event, the 2011 session of the Texas legislature passed a law requiring the PUCT to analyze the preparedness of power plants for extreme weather events as in Section 186.007 of the Texas Utilities Code.[166] The statute required that

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[162] Kent Saathoff of ERCOT Staff (2011), TDSP Curtailment Procedures and Service Restoration Priorities Plan, slide 4. http://www.ercot.com/content/news/presentations/2011/TDU%20curtailment%20workshop%20PUC%2011-3-11.pdf.

[163] Kent Saathoff of ERCOT Staff (2011), TDU Curtailment Procedures and Service Restoration Priorities Plan, slide 5. http://www.ercot.com/content/news/presentations/2011/TDU%20curtailment%20workshop%20PUC%2011-3-11.pdf.

[164] FERC/NERC (2011), p. 9.

[165] FERC/NERC (2011), p, 11.

[166] Texas Util. Code Section 186.007.

power plants submit information to the PUCT about their readiness for extreme weather events, and that the PUCT prepare a report on "power generation weatherization preparedness." More specifically, the statute required the PUCT to "analyze and determine the ability of the electric grid to withstand extreme weather events in the upcoming year" considering anticipated weather patterns. The law also authorizes the PUCT to enact rules relating to the implementation of the weatherization report, and to require power plants to amend inadequate weatherization plans. The PUCT enacted Substantive Rule 25.53 in response to the 2011 legislation.[167] The 2011 law states that this weatherization review process must result in a report by the end of September 2012, but subsequent reports could be filed as deemed necessary. The 2011 law does not explicitly require annual weatherization reports. To date only one report, in 2012, has been filed by the PUCT under Section 186.007, and this 2012 report, written by Quanta Technologies, LLC, identified best practices for winterizing power plants and winterization shortcomings at ERCOT plants.[168] We could not verify whether ERCOT generators implemented those recommendations, or whether the PUCT followed up with generators in connection with those recommendations. ERCOT, however, has held annual "winter weatherization workshops." including a September 2020 workshop that featured winter weather forecasts for 2020-21.[169]

4.3. Comparison of the Three Events

Table 4.a summarizes key indicators for comparison of the 1989, 2011, and 2021 winter events that triggered power outages in ERCOT. Caution must be exercised, however, when drawing any conclusions based on a comparison of these three events. The generation fleet has evolved over time. We have less reliance on coal and greater reliance upon renewable energy resources today. Moreover, the electric and natural gas industries have evolved over the past 32 years. Yet, some observations can be made.

Each of the three winter storms resulted in customer outages or blackouts. During each event, weather-related problems forced outages and de-ratings at power plants and the availability of natural gas to gas-fired power plants was a notable problem.

But these were otherwise very different events. The extent and duration of the outages were far greater in 2021. We are unaware of any loss of life being linked to the electrical outages in 1989 and 2011.

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167 https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.53/25.53ei.aspx.

168 Report on Extreme Weather Preparedness, Best Practices, Quanta Technologies, LLC (September 27, 2012), pp. 7-18.

169 FN--ERCOT and Texas RE Generator Winter Weatherization Workshop by (Webex Only), URL: www.ercot.com/calendar/2020/9/3/210162.

Table 4.a Summary of key metrics summarizing the severity of the 1989, 2011, and 2021 winter storms causing significant power generation outages and derates, load shedding, and low frequency conditions in ERCOT.

Descriptor	Dec. 1989[a]	Feb. 2011	Feb. 2021
Peak Load Estimated w/o load shed (MW)	~ 38,000 + 1,710	59,000[#]	76,819 (estimated by ERCOT)
Maximum load shed (MW)	1,710 4.3% of peak load	~4,900 8.3% of peak load	20,000 26% of peak load
Peak forced and planned Generation Outage as nameplate Capacity (MW) (planned outage in parenthesis)	~ 13,000 (not necessarily simultaneous, unable to determine peak simultaneous outage)	~ 27,200 (12,413)	52,037 (ERCOT, 2021a)
Generation units experiencing an outage (number)	86	193 to 225[170]	~ 585
Customers (meters) without power (millions)	not quantified in 1990 PUCT report	3.2	~ 4.5 (Busby *et al.,* 2021)
Duration of EEA Level 3 condition (hours)	0-9 hours of load shed spread over two different intervals (depending on region)^	~8	~105
Lowest Grid Frequency (Hz)	59.65	59.576	59.302
Natural Gas flows were curtailed to electric utilities and/or generation units before and during blackouts	Yes (< ~1,000 MW)	Yes (1,282 MW)*	Yes (6,700 MW at peak)
Did TDSPs cut off electricity supply to natural gas infrastructure?	unknown	Yes	Yes

a: Information from PUCT (1989).
#: Figure 2 of Potomac Economics (2011).
^: The Emergency Energy Alert (EEA) system did not exist in 1989. ERCOT requested utilities enact Emergency Electric Curtailment Plans (EECP) from Dec. 22, 8:40 am -12:00/12:30 pm (for North & South Texas) and Dec. 23, 6:40 am – 12:40 pm. Utilities reported firm load shedding as occurring on December 23 for: 4 hours (Houston Power & Light), 3.6 hours (City Public Service San Antonio), 2.5 hours (Lower Colorado River Authority).
*: FERC (2011), page 191.

[170] FERC (2011) report states "But over the course of that day and the next, a total of 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW." The Texas RE report states the number of failed or derated generating units was 225.

The 1989 event preceded the introduction of competitive generation and retail markets in ERCOT. The PUCT was able to review the costs incurred by the utilities under its jurisdiction and approve recovery of winterization investments through rates of those costs determined to be reasonable and necessary and prudently-incurred. These post-freeze winterization investments were estimated in the millions of dollars in aggregate (PUCT, 1990). Natural gas prices remained stable throughout the event. There were no significant "wealth transfers" between electricity suppliers and retailers or between industries.

During the 2011 event, the market structure in ERCOT was similar to today's market structure. A nodal wholesale market structure had been introduced in December 2010 – two months prior to the event. Yet, the wholesale offer cap was a much-lower $3,000 per MWh during the 2011 event – one-third of what it is in 2021. As during the 1989 event, natural gas prices remained fairly stable, in contrast to the extreme spike in gas prices experienced in 2021. The financial impacts of the 2011 event received relatively little attention, and we are unaware of data or published estimates of financial impacts.

Ninety-six of the 585 generating units (16.4%) in ERCOT that reported outages or deratings during the winter event in February 2021 also experienced problems during the February 2011 event.[171] This includes four coal-fired generating units which were operated at reduced output levels during the 2021 emergency.[172]

Eight generating units experienced outages or de-ratings during each of the three winter emergencies of 1989, 2011, and 2021. For example, the large Limestone coal/lignite Unit 1 (presently owned by NRG Texas Power LLC) reported problems from low feedwater flow and frozen instruments in 1989, experienced problems in 2011, and was partially de-rated during the winter storm of February 2021. The other seven generating units reporting outages or deratings during all three events were relatively small natural gas-fired combustion turbines or cogeneration facilities.[173] However, this comparison of performance of plants during the three events has limited value, since many power plants in operation today and in 2011 were built after 1989.

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[171] Sources: http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx and PUCT Project No. 27706, filing by ERCOT, Attachment A.

[172] Calaveras Unit JKS2, Oak Grove SES Unit1A, Oak Grove SES Unit2, and Limestone Unit LEG_G1.

[173] These are Air Liquide's Bayou Cogen station's units G2 and G4; Unit1A at Luminant's Stryker Creek plant; Unit 7 at Luminant's Mountain Creek facility; CT4 at Luminant's Morgan Creek plant; and two very small gas turbines at the TH Wharton and WA Parish plants, which are presently owned by NRG Texas Power LLC. Based on publicly-available sources: PUCT Project No. 27706, filing by ERCOT, Attachment A; PUCT (1990); and http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx

5. Summary

The Energy Institute at the University of Texas at Austin assembled a team of faculty and researchers to identify and review credible sources of data in an attempt to provide a factual account of what happened and what went wrong during the winter disaster. Our hope is that this analysis will provide a reasonable basis for subsequent policy decisions designed to improve the performance and resilience of the State's energy systems.

Because of time constraints, data limitations, and the intention to limit the report scope to events and data rather than recommendations, many questions have been left unanswered. For example, we did not analyze the sequences of rolling outages (e.g., on a circuit-by-circuit basis), and we do not yet have a good understanding of what it might take to deploy advanced metering systems to achieve customer outages in a more "rolling" and "surgical" manner than occurred during the 2021 event. We also did not explore whether any natural gas infrastructure facilities were committed to providing an ancillary service during the event, but were unable to perform due to a disruption in their electricity supply.

Our understanding of natural gas flows during the event is incomplete, despite having acquired and analyzed a proprietary source of natural gas data. For example, even without weather-related equipment failures, it is unknown to what level of peak flow rate and duration the Texas natural gas system can deliver natural gas demand to all customers during a winter event such as Winter Storm Uri. A full understanding of the hedging positions and out-of-market contractual agreements among ERCOT market participants will probably never be known given the confidentiality surrounding such agreements, thus limiting our understanding of the full economic consequences of the event. Robust estimations of the cost of better-winterizing the energy supply system will require further site-specific analysis.

It is our hope that subsequent studies – by The University of Texas, other universities, FERC, NERC, and other organizations – may be able to make progress in these areas.

We have intentionally avoided making policy recommendations in this report. Once policy directions are better-established, we would be pleased to contribute analysis designed to explore implementation strategies, the impacts of various policy options, and related issues.

We note that while we were completing this report, the Texas Legislature passed multiple bills in response to the February event, including Senate Bills 2 and 3. These bills focus on weatherization of infrastructure as well as the governance of the grid operator and regulator. Other bills in the 2021 session, such as House Bill 4492, focus on the financial impacts of the winter storm.

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Conflict of Interest Statements

Various participants in the state's natural gas and electricity markets fund research at The University of Texas, and some contributors to this report provide consulting assistance to companies or organizations involved in the energy industry. Disclosures of any relationships that might be perceived to introduce a conflict of interest may be found via the UT Energy Institute and at: https://energy.utexas.edu/ercot-blackout-2021.

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Appendix A. Short History of Texas Electric Grid and ERCOT: From the Beginning to 2021

The current infrastructure, rules, regulations, and organizational roles impacting the ERCOT market are the outcome of many decisions made over multiple decades. Here, we provide a brief history of these decisions to place the ERCOT outages of service in February 2021 in historical context.

For shorthand in this report, we use the acronym "ERCOT" to possibly refer to the wholesale electricity market, the infrastructure that generates and/or delivers electricity, and ERCOT the organization. ERCOT the organization does not own the electricity infrastructure (i.e., power plants, transmission and distribution lines, battery storage) within the ERCOT grid. The grid infrastructure is owned by the generation companies who participate in the market and by transmission and distribution utilities. ERCOT the organization administers the day-to-day electricity market operations and performs transmission planning. The PUCT oversees ERCOT the organization to ensure that it and the market participants comply with the legislative intent and law.

A.1. Why Does Texas Have Its Own Grid?

Electric power development began in the late 1800s as small power plants and local wires were installed in cities across the U.S., including Texas cities. By nature, they were isolated, but eventually grew enough to establish connections among themselves.

The 1935 Federal Power Act established federal jurisdiction over interstate commerce via the Federal Power Commission (FPC), which has since become the Federal Energy Regulatory Commission (FERC). The Public Utilities Holding Company Act (PUHCA) of 1935 created individual companies – utilities – with contiguous service territories. Each utility would act as a monopoly to serve customers within its geographic territory, and in return electricity rates and profits would be subject to state-level approval. PUHCA provided the framework for all electricity service until some regions restructured, or "deregulated," beginning in the 1990s (Tuttle *et al.*, 2016).

Local city grids continued to link to each other, and by the beginning of World War II, the Texas Interconnection System was formed (Cohn, 2017). "Faced with the threat of federal regulation in the wake of the 1935 passage of the Federal Power Act, the principal utilities in Texas … elected to isolate their properties from interstate commerce" (Cudahy, 1995).

In 1965, "North America experienced its worst blackout to date as 30 million lost power in the northeastern United States and southeastern Ontario, Canada" (NERC, 2019). In response, Congress passed the Electric Power Reliability Act in 1967 that led the electricity industry to form the National Electric Reliability Council in 1968, now known as the North American Electric Reliability Corporation (NERC). NERC is a council of regional electricity coordination organizations. In the wake of these changes in federal and national level coordination, in 1970 the utilities operating exclusively within Texas set up their own reliability council named the Electric Reliability Council of Texas, or ERCOT.

The question of electrical isolation of ERCOT utilities was not considered until 1974 when an Oklahoma attorney "… filed a motion with the SEC on behalf of a group of municipal and cooperative electric distribution systems served by Oklahoma Public Service" (OPS) (Cudahy, 1995). OPS was one of four utilities owned by Central and Southwest Corporation (CSW). CSW[174] owned utilities that spanned areas of Oklahoma, Louisiana, Arkansas, and Texas (Cudahy, 1995). A four-year legal battle ensued between CSW and the existing, purely Texas-based, utilities. The dispute was whether to allow utilities to sell or generate electricity within ERCOT from/to states besides Texas and become subject to interstate commerce federal regulatory jurisdiction. CSW wanted electrical connections to transfer electricity to and from Texas, and the ERCOT-only utilities did not.

These battles affected language in the federal Public Utility Regulatory Policies Act (PURPA) of 1978, and the right of the newly formed Federal Energy Regulatory Commission (FERC) to force utilities to interconnect, for example during emergencies, without triggering FERC jurisdiction for other purposes, for example the review of wholesale electricity rates (Cudahy, 1995). Following the passage of PURPA, the utilities in dispute negotiated a settlement. "They finally settled upon a direct current [DC] interconnection [between ERCOT and SPP,[175] or other states] because, unlike an alternating current tie, the power flows over a direct-current link could be controlled. … The parties agreed to other terms as well, notably that the interconnection would not subject ERCOT to federal regulation for other purposes" (Cudahy, 1995). As a result, CSW maintained interconnection across its companies in multiple states, and the ERCOT-only utilities retained state regulation but not federal regulation.

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[174] CSW own[ed] all the common stock of four vertically integrated operating utilities: Central Power and light Company (Central Power), headquartered in Corpus Christi in South Texas; West Texas Utilities Company (West Texas), headquartered in Abilene in West Texas; Public Service Company of Oklahoma (Oklahoma Public Service), headquartered in Tulsa, Oklahoma; and Southwestern Electric Power Company (Southwestern), serving Arkansas, Texas and Louisiana and headquartered in Shreveport, Louisiana." CSW later was merged into American Electric Power, Inc. in 2000 (AEP, 2021)

[175] Southwest Power Pool.

A.2. Wholesale Market Restructuring (Deregulation) and Adjustment Timeline

In 1995 the Texas Legislature passed Senate Bill 373 to restructure the electric generation sector in ERCOT. The bill ensured equal access to the transmission grid for power generators and established ERCOT as the Independent System Operator (ISO) in 1996, the first ISO in the U.S. although its initial functions were very limited relative to today's ISOs. Before this time, ERCOT was only the reliability coordinator that reported to NERC (ERCOT, 2016). "Additional objectives of SB 373 were to ensure an equitable interconnection process, facilitate generation capacity and transmission expansion, and provide customer protection."[176] (Adib and Clark, 1996)

In addition to further restructuring wholesale power generation, Texas SB 7 in 1999 ordered the introduction of retail competition in the service areas of the investor-owned utilities within the ERCOT power region by 2002. By 2002 the investor-owned utilities in the ERCOT power region which were previously vertically-integrated were "unbundled," or separated, into three separate entities: power generation, transmission and distribution utilities, and retail electric providers (REPs). Rural electric cooperatives and municipal utility systems were permitted to either participate in retail competition ("opt in") or decline to participate, although changes in the wholesale market would affect them regardless of their decision.[177]

Prior to restructuring, generation dispatch decisions and other operational decisions were made locally in ten control areas. However, ERCOT transitioned to operating as a single control area under the legislative framework established through SB 373 (in 1995) and SB 7 (in 1999).[178]

While markets were developed for wholesale generation and retail activities, investor-owned TDSPs remain under conventional regulatory oversight.

SB 7 also gave the PUCT authority over market oversight, including oversight of ERCOT. SB 7 sought prevent the exercise of market power, including the provision that no single generation company can control more than 20% of the total installed generation capacity.[179] Via ERCOT's bylaws (as an ISO) and authority of the PUCT, a stakeholder process provides the opportunity for stakeholders (generators, TDSPs, consumer groups, etc.) to participate in the design and operation of the electricity market.

SB 7 set a Texas renewable portfolio standard (RPS) of 2,880 MW (adding 2,000 MW to 880 MW of existing capacity) of renewables and created a renewable energy

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176 For SB 373, see: https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=74R&Bill=SB373.

177 See SB 7 (https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=76R&Bill=SB7) Sec. 41.051 (cooperatives) and Sec. 40.051 (municipal utilities).

178 http://www.ercot.com/news/releases/show/77

179 Luminant (a subsidiary of Vistra) owns almost 20% of generation in ERCOT.

credit (REC) market to facilitate that standard. In 2005, Texas legislators increased the RPS to 5,880 MW of renewable capacity, and via SB 408 directed the PUCT to facilitate the process to design and construct new transmission to serve a set of "Competitive Renewable Energy Zones" (CREZ). As of the end of 2020, approximately 25,000 MW of wind and 4,000 MW of solar photovoltaic capacity were installed in ERCOT, thus far surpassing the RPS.[180]

Table A.1. Timeline of the Evolution of a Competitive Market in ERCOT[181]

1975	Passage of the Texas Public Utility Regulatory Act (PURA), establishing the PUCT.
1978	The federal Public Utility Regulatory Policy Act (PURPA) is enacted, facilitating and providing a pricing mechanism for utility purchases of power from cogeneration and small power production.
1983	Amendments to the Texas PURA to reflect the 1978 enactment of PURPA and introduction of the elements of integrated resource planning, such as a ten-year demand and resource forecast. The PUCT is no longer responsible for forecasts and planning for electric grid investments.
1992	The passage of the US Energy Policy Act.
1995	State Legislature passes Senate Bill 373 amending the Texas PURA to introduce wholesale competition in September 1995.
February 1996	The Commission establishes the requirement for ERCOT to become an Independent System Operator (ISO) and requires utilities to offer wholesale open-access transmission service.
Late 1990s	The PUCT approved an interconnection rule to facilitate merchant plant development.
May 1999	State Legislature passes Senate Bill 7 amending the Texas PURA to introduce retail competition on January 1, 2002 and further restructure the wholesale market.
2000-2001	The PUCT finalized its decision regarding functional unbundling plans for integrated utilities. In addition, the Commission

[180] See ERCOT "Resource Capacity Trend Charts" at http://www.ercot.com/gridinfo/resource (e.g, December 2020: http://www.ercot.com/content/wcm/lists/219848/Capacity_Changes_by_Fuel_Type_Charts_December_2020.xlsx).

[181] Some information included in this table is from Adib and Zarnikau (2007).

	finalized several important rules to enhance the transition to competition within ERCOT.
August 2000	The PUCT established Wholesale Market Oversight to monitor market activities and detect market power abuses and other market manipulation.
June 4, 2001	The PUCT finalized its decision with regard to the ERCOT Protocols that established market rules for the wholesale electricity market.
July 31, 2001	The operation of the ERCOT single control area began and a pilot retail program was introduced.
January 1, 2002	Customer choice began within ERCOT electricity market and "price to beat" was established within each incumbent investor-owned-utility service area and became effective for residential and small commercial customers with peak load lower than 1 MW.
September 2002	Retail Market Oversight was established to monitor the retail market and identify areas for improvements.
February 2003	Price spikes in wholesale market prompt re-examination of the use of balancing energy, wholesale price mitigations formulas, and credit requirements for REPs.
Late 2004	Switching rates for commercial energy consumers exceeds thresholds and the "price to beat" for commercial customers is terminated in many service areas.
September 2005	PUCT decides to transition market to a nodal structure.
2005	Texas Legislature adopts SB 408 designating the creation of Competitive Renewable Energy Zones and provides authority to PUCT to direct ERCOT to plan for transmission to connect approximately 18 GW of wind capacity.
2005	The legislature adopts SB 408 that increases the number of independent representatives on ERCOT's board and designates an independent monitor for the wholesale electricity market[182].
August 2006	The PUCT approves rules (Subst. R. §25.505) for "scarcity pricing" with new energy offer caps.

[182] SB 408 (79R Legislative session in 2005): https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=79R&Bill=SB408.

2010	On December 1, the nodal wholesale pricing system goes live approximately four years after initially planned. Along with nodal pricing comes the "day ahead market" for individual power plants to bid for next-day electricity generation on a 15-minute basis.
October 2012	PUCT approves a timeline to gradually increase the energy offer cap to $9,000 per MWh through amendments to Subst. R. §25.505.
June 2014	Operating Reserve Demand Curve (ORDC) is first implemented, to raise energy prices when physical operating reserves are low.
January 2019	The PUCT orders a shift in the ORDC to increase energy prices further when operating reserves dwindle. PUCT also decides to implement real-time co-optimization in the selection and pricing of energy and ancillary services in the wholesale market.[183]
March 2020	A further shift in the ORDC is implemented.

A.3. Why isn't ERCOT Connected to Other Grids?

Previous paragraphs summarize the history of the ERCOT grid as separate from others in North America. However, the costs and benefits of interconnecting ERCOT with neighboring reliability councils were studied in the late 1990s, per a request by the Texas Legislature.[184] The established Synchronous Interconnection Committee (SIC) failed to reach a definitive conclusion regarding whether the benefits of interconnection would likely outweigh the costs:

> *Due to the complexities of the issues and uncertainties surrounding the evolving electric marketplace, the SIC was unable to conclusively establish that AC interconnection is, or is not, desirable either as a candidate transmission investment or as an instrument of policy to promote competition in future electricity markets.*[185]

It is possible that a similar analysis today would yield differing results, as questions remain surrounding the costs and benefits of greater interconnection with neighboring markets or reliability councils.

[183] See PUCT Project No. 48540.

[184] Per SB 373 (74th legislative session in 1995).

[185] SIC, 1999, cover letter.

A.4. Today's ERCOT Wholesale Market

Today, ERCOT serves 90% of the electric load in Texas. This power region has experienced consistent load growth in recent decades due to a strong economy and increasing population, unlike some other U.S. markets which have experienced little growth. Currently, 26 million people within Texas receive electric service via the electric grid managed by ERCOT.

ERCOT administers day-ahead and real-time markets for energy, as well as a day-ahead market for ancillary services (AS). ERCOT is relatively unique in that it is an "energy-only market" and thus does not operate a capacity market or impose resource adequacy targets in order to maintain a target reserve margin.[186] Market forces are heavily relied upon to provide enough generation for resource adequacy, and market price offer caps have been raised to relatively high levels in hopes of providing sufficient compensation to the generation sector to incentivize investment to meet peak electricity demand. The price offer cap has increased almost 10-fold over a span of 13 years to $9,000/MWh. While normal market operations can push prices to scarcity levels, multiple price add-ons have been developed to increase prices when reserves are low or emergency reliability actions have been taken.

ERCOT retains only a few small direct current (DC) interconnections with neighboring markets and reliability councils, and remains a fully intrastate system with limited federal jurisdiction over its market.

A.5. Characteristics of the ERCOT Retail market

Of the approximately 11 million metered customers in ERCOT, [187] about 8 million have retail choice and can select among different retail electric providers offering different electricity pricing plans and services.

Efforts to introduce competition into the retail sector of the state's electricity market began in June 1999 with the passage of Senate Bill 7 (SB 7) by the Texas Legislature. SB 7 permitted retail competition in the service areas of the investor-owned electric utilities within ERCOT's power region on a commercial basis beginning January 1, 2002. These service areas, identified in Figure A.1., include two of the nation's ten largest metropolitan areas – Dallas/Fort Worth and Houston. New entrants were permitted to compete with retail arms of five utilities that were formerly vertically-integrated: Houston Lighting and Power Company, TXU Electric, AEP-Texas North, AEP-Texas Central, and Texas-New Mexico Power Company. Oncor became the TDSP successor to TXU Electric, while CenterPoint Energy is the TDSP successor to Houston Lighting and Power Company.

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[186] Other "energy only" markets include electricity markets in Alberta and Australia.

[187] http://www.ercot.com/content/wcm/lists/219736/ERCOT_Fact_Sheet_1.04.21.pdf

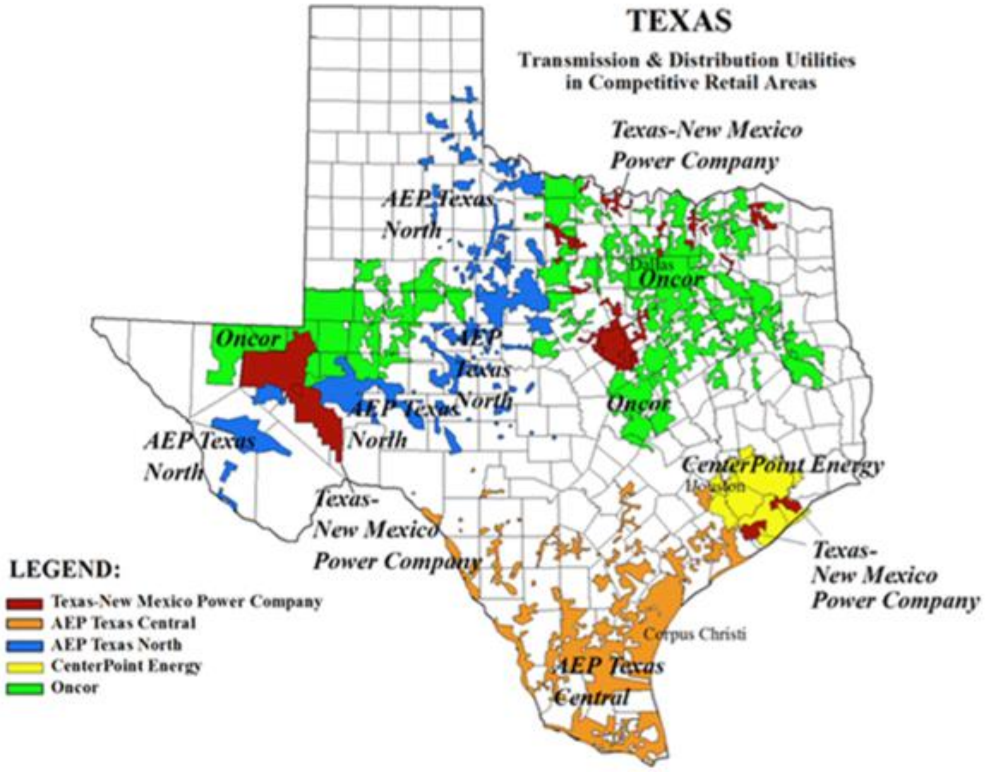

Figure A.1. Areas Initially Opened to Retail Competition. Source: PUCT at: https://www.puc.texas.gov/industry/maps/maps/tdumap.pdf.

At the start of retail competition in 2002, certain constraints were placed upon the prices charged by the five retailers that were successors of former vertically-integrated utilities (then known as the AREPs, or affiliated retail electric providers). After January 1, 2005, the AREPs were allowed to provide alternative prices to their customers, provided these alternative pricing plans did not exceed the "price to beat" (PTB) set by the PUCT. By December 2007, approximately 40 percent of residential customers in areas exposed to retail competition had switched to a competitive retailer – i.e., a retailer other than one that was a successor to one of the former vertically-integrated utilities – or a different AREP. On January 1, 2007, PTB constraints fully expired, removing any regulatory oversight over retail prices. The outcome was an overall reduction in average prices (Zarnikau and Kang, 2009; Swadley and Yucel, 2011).

Before retail choice was implemented in Texas, Direct Energy entered the Texas retail market by purchasing the retail branches of AEP-Texas North and AEP-Texas Central (formerly known as West Texas Utilities and Central Power and Light). Another of the five original AREPs changed ownership when Reliant Energy – a successor of Houston

Lighting and Power Company – was acquired by NRG Energy in 2009.[188] In 2011, Direct Energy acquired another original AREP – First Choice Power, the retail affiliate of Texas-New Mexico Power Company.[189] The last remaining AREP, TXU Energy, was acquired by a group of private investors (led by KKR, TPG Capital, and Goldman Sachs) in 2007. Following a bankruptcy in 2013, TXU Energy and its generation affiliate (Luminant) were renamed as Vistra Energy in 2016.[190]

In recent months, following the merger of NRG Energy and Direct Energy, concerns have been raised over market concentration in ERCOT's retail market. After the completion of the merger on January 2, 2021, NRG Energy and Vistra control about 78% of the *residential* retail market, though concentration in other market sectors (e.g., commercial and industrial market segments) is lower (Brown, et al, 2020).

On the competitive retail side, the 2021 winter event has reduced the number of retailers. Griddy Energy, Entrust Energy, and Power of Texas Holdings have left the market and Just Energy Group has filed for bankruptcy. By February 24, 2021, the number of competitive rate options advertised on the PUCT-administered Power to Choose website had dropped by half.[191] A departure of retailers from the market has occurred in the past,[192] but the number of retailers that have left the market recently is unprecedented.

A.6. Summary: ERCOT History and Current Status

The ERCOT grid and ERCOT the organization have changed considerably since the Texas legislators ordered restructuring of wholesale markets. Wind and solar generation were practically zero in 1999, but amounted to 25% of the 381 terawatt-hours (TWh) of generation in 2020 (Figure A.2) Natural gas generators have provided 40-46% of generation during the last 15 years, while coal generation had declined from 40% in 2010 to less than 20% in 2020. There are currently no plans to build new nuclear power plants in ERCOT.

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[188] https://en.wikipedia.org/wiki/NRG_Energy; https://www.power-grid.com/td/nrg-energy-to-acquire-reliant-energys-texas-retail-business/#gref

[189] https://www.prnewswire.com/news-releases/direct-energy-to-acquire-first-choice-power-for-270-million-130411228.html

[190] https://www.txu.com/company/why-txu-energy/about-us.aspx; https://www.dallasnews.com/business/energy/2016/11/04/luminant-and-txu-energy-have-a-newly-named-corporate-parent-vistra/

[191] Based on calculations performed by Hen-Hao Tsai, a former researcher at UT-Austin who is now employed by MISO. Communicated via email to Jay Zarnikau on Feb. 24, 2021.

[192] Based on ERCOT's public notices, retailers that have left the market prior to 2021 include: Texas Commercial Energy (2003), Utility Choice Electric (2004), Ampro (2006), Buy Energy (2006), Franklin Power (2005), Blu Power of Texas (2008), Hwy 3 MHP (2008), Sure Electric (2008), Pre-Buy Electric (2008), National Power Company (2008), Abacus Resource Energy (2011), EPCOT Electric (2012), TexRep7 LLC (2012), Reach Energy (2014), Proton Energy (2014), and Reach Energy (2014).

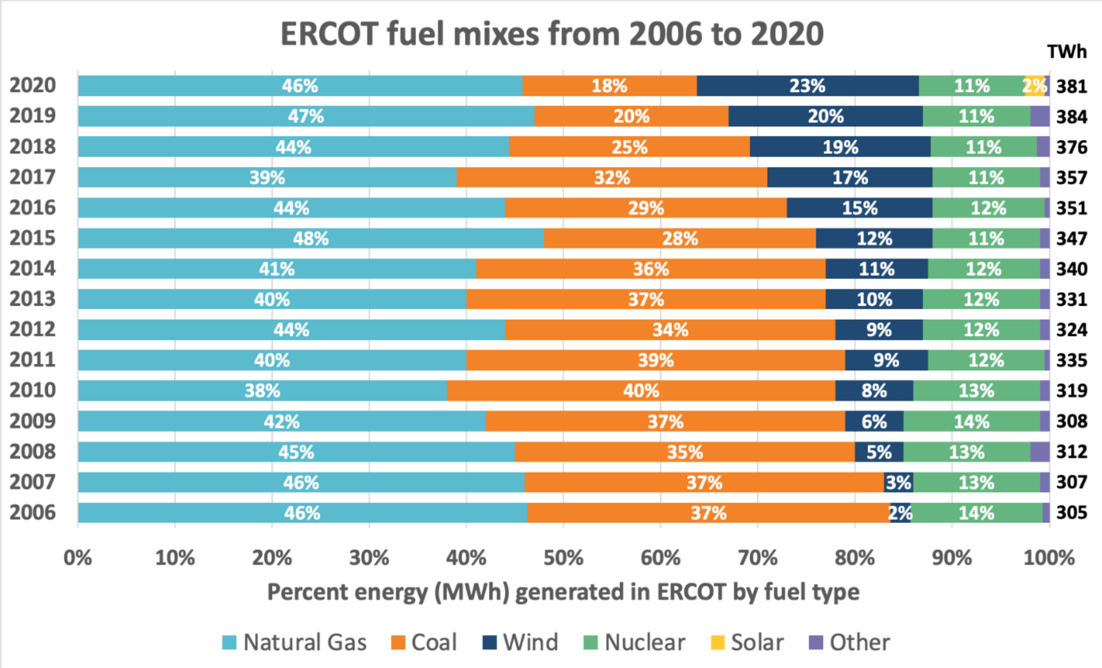

Figure A.2. The percentage of annual electricity generation in ERCOT, by fuel, from 2006-2020

Appendix B. Internal ERCOT Meteorological Discussions Before the Storm

To help forecast electricity demand or "load" and make other preparations for day-to-day grid operations, ERCOT utilizes multiple weather models, NOAA forecasts, as well as data from outside weather vendors to inform their internal predictions about short and long-term weather across the state. Communications between the resident meteorologist and various planning, outage, and resource groups at ERCOT indicate the difficulty in forecasting the onset and severity of Winter Storm Uri of 2021. These day-to-day communications are internal to ERCOT, but ERCOT issues outside communications to market participants to warn of major weather events that could impact market operations.

Of the internal ERCOT emails we reviewed; one written January 28 was the first mention that ERCOT would experience a spate of cold weather. This e-mail noted that February is that hardest month to forecast, but that there was evidence that February 2021 would be colder than normal. Another email on February 1 indicated that a polar vortex was working, but it was likely to be pushed east of Texas. On February 3, an email indicated that there was a good chance that February was going to be the coldest weather of the 2020/2021 winter, but the models used for predictions were varying widely with forecasted lows for Austin varying between 19°F and 53°F on February 8. By February 4 the various models were converging on Dallas and Austin seeing their coldest weather of the year, with a good chance of Houston and possibly for Brownsville also seeing their coldest temperatures of the year. On February 5, the models began to diverge on the timing of when the cold air masses will arrive in Texas. The February 6 weather update compares the coming cold to January 2018 in severity. The February 7 update explained that the models were still 20-30 degrees apart in their temperature predictions with the coldest model showing cold weather similar to January 2018.

By February 8 the models began to trend back together, showing February 14 to be very cold. The meteorologist noted that "[t]his is the most challenging, worrisome forecast since I joined ERCOT…" One of the models indicated a scenario that would rival the weather event of 1989, but the forecasted cloud cover made it hard to believe. Also, there were still tens of degrees difference between the various models, but they were trending to levels equivalent to the extreme cold weather experienced in February 2011. The February 8, 2021 update was the first to mention that there could be significant icing issues with this storm.

The February 9 update indicates that the models were in agreement that February 14 – February 17 would be very cold, but that there was still a 15-20°F difference between them. The February 9 update also noted that there was a high chance of freezing rain in West Texas in the short-term, and that there likely wouldn't be enough time for it to melt before the coldest temperatures arrived. On February 10 some of the models that have been predicting warmer weather began to predict weather closer to the coldest model, and a December 1989-like scenario can't be ruled out. Additional information conveyed on February 10 said that the 2011 February 2 freezing conditions arrived much more abruptly than the anticipated oncoming freezing conditions over the oncoming week of 2021. A February 11 weather update indicated that the event could last as long as February 18.

The February 12 weather update indicated that the forecasts were all trending colder, and that the models were having trouble accurately in predicting snow this late in the winter (mid-February) because there was a lack of historical precedent for snow this late in the winter. The February 12 update further noted that there were continued disagreements between models and vendor-supplied temperature forecasts and that "ERCOT simply hasn't seen anything quite like this – this late into the winter."

On February 13 the weather models were still disagreeing on the severity of the coming cold in some parts of the state, and the ERCOT meteorologist communicated a possibility of a second winter storm that would hit mid-week, bringing more snow. The ERCOT meteorologist also noted that they could not rule out forecasted lows in the mid-teens (degrees Fahrenheit) in the Rio Grande Valley.

The last of the supplied emails, from February 14, discussed that all but one solar farm in ERCOT was likely to receive snow and that the models still had disagreements of between 10-15ºF in the severity of the cold over the next few days, making forecasting difficult. In this email, it was also noted that Dallas temperatures on February 14 were currently below the latest forecasted levels.

The internal meteorological communications reviewed appeared to describe a very difficult storm to predict, oh which the intensity wasn't fully realized until just before it happened.

Appendix C. Generator Outages Relative to Time Reaching Freezing Temperature

Another relevant question to ask in assessing the electric grid's ability to withstand freezing conditions is "How long do generators experience freezing conditions before generators experience outages?" That is to ask, if a sub-freezing winter storm arrives in Texas, how much time does it tend to take for power generation to go offline, for any reason?

We display the timing of the February 2021 outages in Figure C.1., with respect to when power plants first reached freezing temperature (0°C or 32°F). Some parts of Texas, for example the panhandle, reached freezing temperatures days before the southern coastal parts of Texas reached freezing temperatures — the figures account for this difference.

Figure C.1 combines the MERRA-2 weather data with ERCOT's publicly reported timing of generator outages as compiled within the "ERCOT's Generator Outage/Derate Visualization App" (EGOVA) dataset that relates the generators to power plants in U.S. government databases with location data.[193] We first associate a MERRA-2 temperature time series with each power plant based on the nearest weather station. Then, starting with the first hour on February 5, we find the first hour with a temperature at or below 0°C, and plot the reported generation outages relative to the time at which the power plant first experienced 0°C.

It is easiest to explain the methodology for the concrete example of the nuclear generator that experienced an outage. ERCOT reported that South Texas Nuclear Project (STNP) generation unit #1 experienced an outage from February 15 at 5:27 am to February 17 at 9:07 p.m., a span of approximately 64 hours. The MERRA-2 weather data suggest that STP reached 0°C at approximately 2 am on February 15. Thus, STP went offline approximately 3 to 4 hours after reaching 0°C, and the figure for Nuclear indicates STP's capacity reduction starting *4 hours after first reaching 0*°C. Similarly, 64 hours after going offline, STP operators brought the generator back online, and the capacity reduction returned to zero at *68 hours after first reaching 0*°C*,* since the generator was at full capacity at that time.

If a power plant experienced a capacity reduction, generation derating, or outage, *before reaching 0*°C, that is reported as a negative value (*before)* the 0-hour on the x-

[193] https://bit.ly/EGOVADatabase

axis. Figure C.1 sums all capacity outages for plants of the same fuel relative to the time they experienced freezing temperatures.[194]

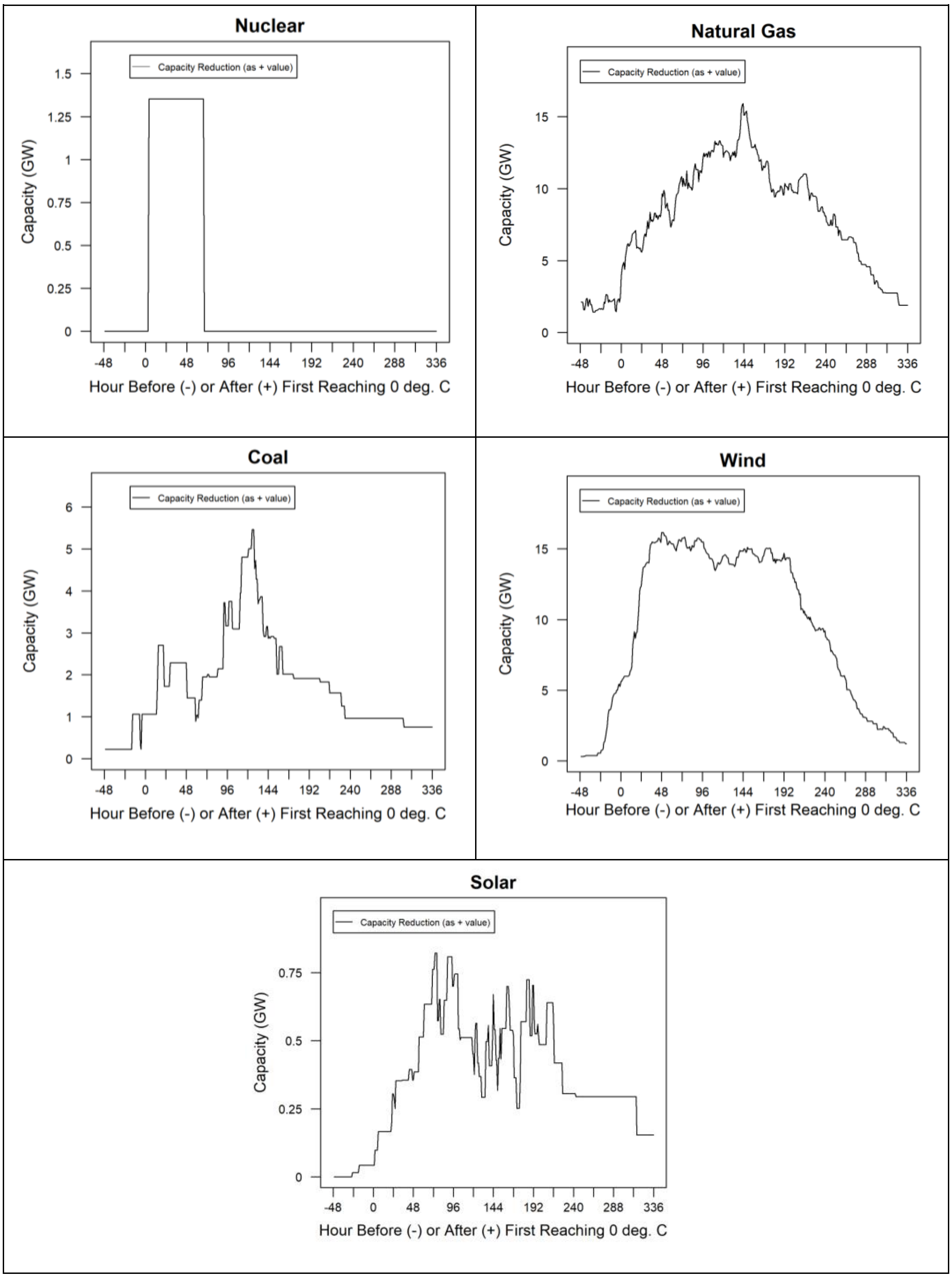

Figure C.1. The capacity reduction (generation outages) for all types of generators relative to when they first experienced 0°C.

[194] That is to say, if two natural gas generators, with capacity reductions of 100 MW and 200 MW, respectively, experienced their outage 3 hours before reaching 0°C at each location, then this would be shown as a 300 MW outage at the x-axis value of –3, for 3 hours before reaching 0°C.

We can draw some conclusions from Figure C.1, but there are many caveats. One takeaway is that the duration of freezing temperatures is important, in addition to the temperatures experienced. Compared to wind and solar outages, the peak coal and natural gas generator outages occur at much longer intervals of time after reaching freezing temperatures. The peak capacity of outages, relative to the time when the plants first experienced freezing temperatures, was approximately 6 days for natural gas plants, 5 days for coal plants, 1 day for wind turbines, and 3 days for solar generators. This result suggests that a multitude of complicating factors might accumulate or occur after many hours at, or below, freezing temperatures to affect natural gas and coal generation. The impacts to wind and solar farms appear to occur relatively quickly, which is consistent with the reporting suggesting that a majority of their outages were related to snow or ice accumulation.

Some of the caveats in the interpretation of Figure C.1 include the lack of other weather data, such as precipitation and wind speed, as well as other factors that caused power generator outages, such as fuel limitations and other mechanical failures. For example, it is possible that the same cold temperatures with dry, rather than wet, conditions could have caused fewer generation outages from all types of generators. Further, generation units experience outages on a regular basis that are independent of the weather.

Appendix D. Texas Natural Gas Balance

Per the U.S. Energy Information Administration (EIA), Texas is the largest energy-producing and energy-consuming state in the U.S., including crude oil and natural gas. In 2020, Texas accounted for 43% of the U.S. crude oil production and 26% of its marketed natural gas production.[195] Texas also consumes more energy (in aggregate) than any other state.

The extreme cold weather from Winter Storm Uri and associated electricity supply disruptions caused serious interruptions in Texas natural gas supply due to freeze offs in field operations in the oil and gas value chain. The storm affected rates of natural gas production and industrial sector consumption with both experiencing their largest monthly declines on record. During the same period, residential consumption reached record highs.

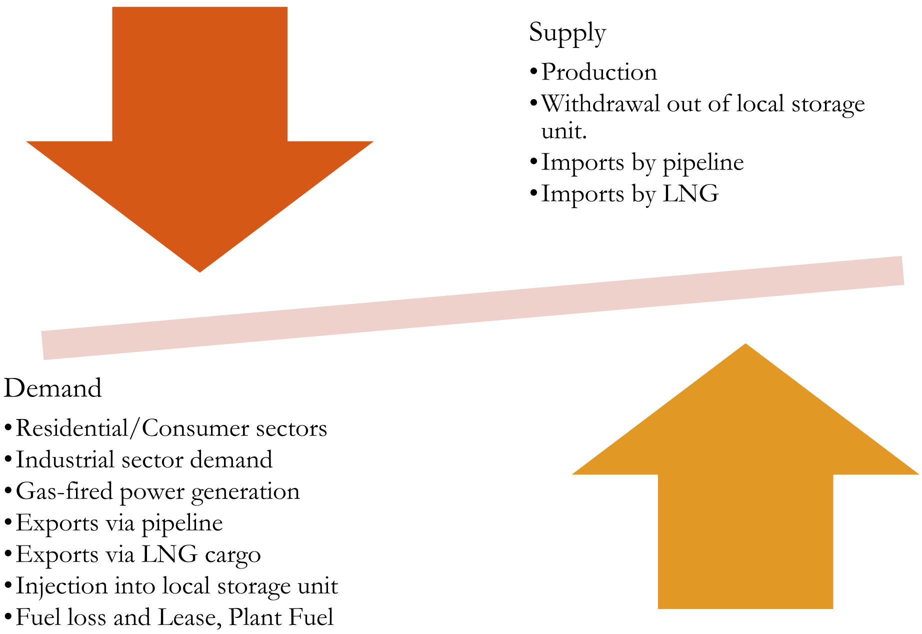

Figure D.1. Overall Natural Gas Balance

To contextualize natural gas operations during the storm and associated blackout, it is important to understand the natural gas balance of Texas (see Figure D.1. Overall Natural Gas Balance). There are three major sectors of the natural gas value chain; production, transmission and distribution. The balance of the market describes the aggregated relation between the supply and demand segments. There are multiple ways to supply a market with natural gas, including local production, local withdrawal from storage, and imports regions. There are also multiple demands for natural gas: including distribution to downstream consumers in individual market segments, injection into underground storage units, and exports to

[195] EIA: [Texas - State Energy Profile Overview - U.S. Energy Information Administration (EIA)]

other markets. There are five major segments of demand for natural gas – residential, commercial, gas-fired electricity generation, industrial, and transportation.

Figures D.2 and D.3 show the monthly natural gas supply-demand balance[196] in the state of Texas from January 2016 to February 2021. Aggregate natural gas supply in Figure D.1 includes two major supply sources, dry gas production and net storage withdrawal. Dry gas production[197] refers to the process of producing consumer-grade natural gas, after removing nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen), and it does not include any volume used for production at the lease site, or any processing losses. The volumes of dry gas withdrawn from gas storage reservoirs are separate and not considered part of production. Dry natural gas production equals marketed production less extraction loss. Aggregate natural gas demand includes three categories: 1) local gas deliveries,[198] 2) net exported gas,[199] and 3) losses of natural gas in field extraction and processing, as lease and plant fuel, and as pipe loss fuel. Figure D.3 shows an increasing demand for Texas exports of natural gas via pipeline and LNG to other markets.

The aggregated supply side should equal to the aggregated demand side, theoretically. Though in reality, there is often a small balancing item representing any quantities lost and imbalances in the data due to differences among data sources. This balancing item is usually around 0.5-1.5%.

$$Production + Net\ Withdrawl\ from\ Storage =$$

$$Consumption + Net\ Pipeline\ Export + Net\ LNG\ export + (Fuel\ loss + LPF)$$

[196] Figure D.2 – 5 GPCM® Base Case Database as of 2021 Q1 a market simulator for North American Gas and LNG™ by RBAC.

[197] EIA: Definitions, Sources and Explanatory Notes on natural gas.

[198] Including electric generation, residential, and commercial customers

[199] Gas exported Texas via pipeline to other states and Mexico, as well as net exported gas as liquified natural gas (LNG) cargo to international destinations

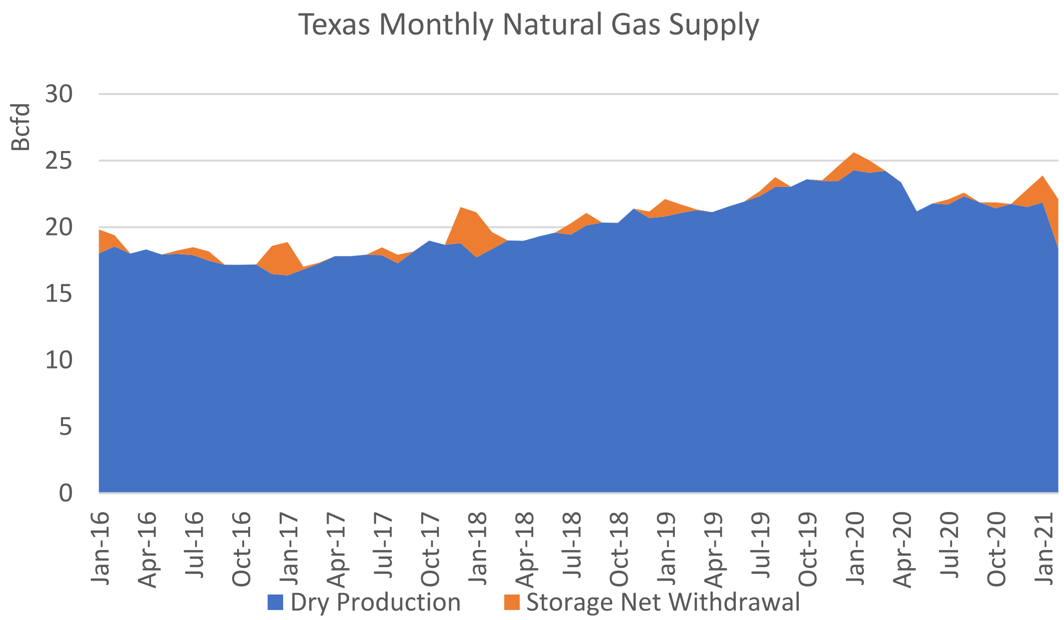

Figure D.2. Texas Monthly Natural Gas Supply (Source: GPCM™)

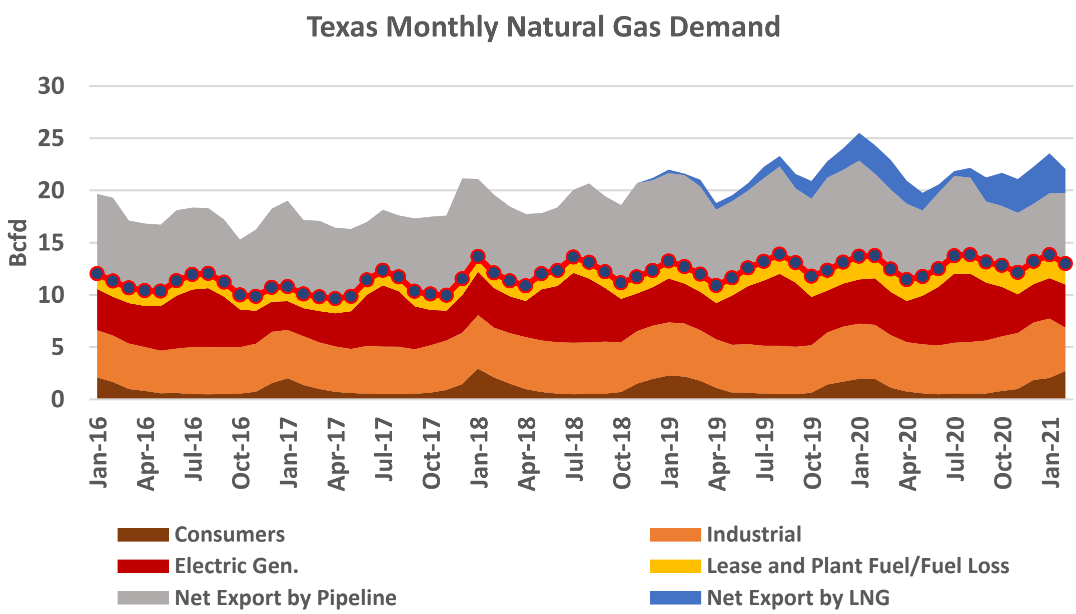

Figure D.3. Texas Monthly Natural Gas Demand (Source: GPCM™)

Appendix E. Other (non-energy) Infrastructures Impacted from Storm: Water and Housing

The winter storm's impacts did not stop with the electricity and gas infrastructure. The storm also directly and indirectly impacted other infrastructures, including water and housing. At one point, up to 12 million Texans[200] were without water or under boil advisories due to either low water pressure or damaged treatment facilities.[201] While property damage was not limited to Texas, the state is expected to file roughly half the insurance claims associated with the winter storm.[202] The Federal Reserve Bank of Dallas estimates that insured losses in Texas alone range between $10 billion and $20 billion.[203] The Dallas Fed estimates that total losses from the storm could approach $130 billion in direct and indirect costs, while other estimates put it as high as $300 billion.[204]

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200 https://www.texastribune.org/2021/02/17/texas-water-boil-notices/

201 https://www.dailysentinel.com/social_media/article_e3e219d1-e267-513d-848d-10dc3109e595.html.

202 https://www.wsj.com/articles/winter-freeze-damage-expected-to-hit-18-billion-from-burst-pipes-collapse-roofs-11613757414.

203 https://www.dallasfed.org/research/economics/2021/0415.

204 https://www.perrymangroup.com/media/uploads/brief/perryman-preliminary-estimates-of-economic-costs-of-the-february-2021-texas-winter-storm-02-25-21.pdf.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-21-41

IDAHO POWER COMPANY

ATTACHMENT 4

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Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

Primary Credit Analyst:
David Bodek, New York (1) 212-438-7969; david_bodek@standardandpoors.com

Secondary Credit Analysts:
Richard W Cortright, Jr., New York (1) 212-438-7665; richard_cortright@standardandpoors.com
Solomon B Samson, New York (1) 212-438-7653; sol_samson@standardandpoors.com

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Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	**Assumption**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Thereafter**
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

Additional Contacts:
Arthur F Simonson, New York (1) 212-438-2094; arthur_simonson@standardandpoors.com
Arleen Spangler, New York (1) 212-438-2098; arleen_spangler@standardandpoors.com
Scott Taylor, New York (1) 212-438-2057; scott_taylor@standardandpoors.com
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-21-41

IDAHO POWER COMPANY

REDACTED

ATTACHMENT 5

80MW Solar Resource Financial Analysis

PPA and Utility Ownership Customer Costs ($M)

Line No			Total		Present Value
1	20-yr PPA Cost	$	[redacted]	$	[redacted]
2	Replacement Energy Cost (yr. 21-35)				
3	Imputed Debt Cost				
4	Total PPA Customer Cost	$	416.9	$	124.9
5					
6	35-yr Utility Ownership	$	240.7	$	94.8
7					
8	Customer Savings (line 4 - line 6)	$	176.2	$	30.1

[1] 20-yr PPA cost [redacted] at year 1 escalating at [redacted] per year
[2] Replacement energy costs determined from market rates as prescribed in Idaho Power's 2019 IRP WECC planning case
[3] Imputed Debt calculated for original 20-yr PPA and replacement energy contract
[4] Assumes 26% investment tax credit (ITC)

Attachment B

Idaho Power's Notice of Intent to Seek Proposals for New Resources: Question and Answer Excerpt from December 22, 2021

REQUEST FOR NEW RESOURCES NOTICE OF INTENT: QUESTIONS AND ANSWERS

TO: All Prospective Respondents

DATE: December 22, 2021

The following questions and answers are related to Idaho Power's Notice of Intent to seek proposals for new resources. If you have further questions, please email ResourceNOI@idahopower.com. Additional updates will continue to be posted idahopower.com/resourcerequests.

Submitted Questions and Answers:

- ***Question*:** Will standalone storage projects only be contracted though an Asset Purchase contract (i.e. 2021 all-source), or will PPAs also be a possibility for this asset class?

  ***Answer*:** Standalone Battery Energy Storage Systems (BESS) submittals must provide a contract structure that will lead to IPC ownership at the commercial operation date.

- ***Question*:** Is Idaho Power Company considering Geothermal resources in this forthcoming RFP?

  ***Answer*:** IPC is considering multiple technologies as part of the forthcoming RFP, including Geothermal.

- ***Question*:** Will Idaho Power Company be considering Power Purchase Agreements (PPA), and Build-Operate-Transfer Agreements (BOT or BTA) as part of this RFP, or will Idaho Power also consider a self-build option?

  ***Answer*:** IPC is considering several contract structures pertaining to multiple resource technologies. These details, will be further described in a Product Table listed in the RFP. IPC will be submitting a "self-build" resource proposal.

Intent to Bid Requirement Reminder:

If you are interested in submitting a proposal in response to the forthcoming request for resources, please return a completed electronic copy of the Notice of Intent Form to ResourceNOI@idahopower.com no later than **5:00 p.m. MT on December 23, 2021**. Thank you for your participation and continued interest in this process.

Idaho Power Company
Request for Resource Team
1221 W. Idaho St. | Boise, ID | 83702
resourceNOI@idahopower.com