The 2021 ERCOT Power Crisis. Capacity Markets Would Not Have Helped

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Abstract

In the aftermath of the February 2021 Texas power crisis, some have called for ERCOT to adopt a capacity market. An analysis of the relevant events, however, shows that a capacity market would have been unlikely to avoid or even substantially alleviate the crisis.

I. Introduction

As is commonly known, the Texas ERCOT market does not have a capacity market, unlike the Regional Transmission Organizations (RTOs) in the Northeastern United States. Instead, to attract sufficient generation, ERCOT relies on a high price cap of $9000/MWh in its energy market and an Operating Reserve Demand Curve (ORDC) adder that pays additional funds to generators supplying power and ancillary services when supply conditions are tight.[2]

In the aftermath of the February 2021 Texas power crisis, some have called for ERCOT to adopt a capacity market (e.g., Hirs 2021).[3] An analysis of the relevant events, however, shows that a capacity market would have been unlikely to avoid or even substantially alleviate the crisis. Section II reviews the February 2021 event. Section III examines how a capacity market might have affected the crisis. Section IV briefly examines alternative policies that may be more helpful to ERCOT in preventing or ameliorating a similar crisis in the future.

II. The February 2021 Event

Three factors convened to turn the unusually intense winter storm of mid-February 2021 into a full-blown crisis for the Texas power sector.[4] First, extremely cold temperatures increased demand for electricity. As temperatures plummeted, consumers sought large quantities of electricity to heat their often poorly insulated homes and businesses. The average load for the ERCOT system on February 14 was 55,020 MW—49 percent higher than the average load of 36,900 MW just a week before, on February 7 (ERCOT 2021). Load soared to over 69,000 MW on the evening of February 14.

Second, the cold temperatures persisted for almost four days, placing a prolonged strain on electricity supply. Temperatures were below freezing in Dallas for 140 consecutive hours, in Austin for 162 hours, and in Houston for 44 hours (Magness 2021, 18). The duration of the crisis greatly exacerbated the harms that it imposed on Texas electricity consumers.

Third and most important, generation supply fell significantly. Even as demand surged, ERCOT generation fell from approximately 71,000 MW in the evening of February 14 to approximately 47,000 MW on the afternoon February 14. This led to the onset of blackouts early on February 15 (Magness 2021, 12, 14-15). At least on paper, ERCOT had sufficient generation capacity to meet the great majority of even heightened demand. The amount of generation that was actually able to produce electricity during the crisis, however, fell substantially below normal.

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While the cold affected all major types of generation, the largest impact was on natural gas generators. Electricity generated by natural gas fell from approximately 43,000 MW at midnight on February 14 to less than 30,000 MW at noon on February 15 (EIA 2021), even though power prices soared to the cap of $9000/MWh (Magness 2021, 22). Table 1 summarizes the capacity available from natural gas, wind, and solar during the most critical times of the blackout, from 1:00 AM on Monday, February 15, to midnight on Wednesday, February 17.

Table 1: ERCOT Generator Performance During February 2021 Event

	All Generation	Natural Gas	Wind	Solar
Mean Production (MW)	47,404	30,131	3,429	798
Standard Deviation (MW)	7,121	2,716	1,730	1,091
% Standard Deviation	15.0%	9.0%	50.5%	136.7%
Maximum Output (MW)	68,021	42,372	8,261	3,512
Minimum Output (MW)	41,709	25,964	649	0
Total Capacity (MW)	108,017	51,667	31,390	6,177
Average Capacity Factor	43.9%	58.3%	10.9%	12.9%
Maximum Capacity Factor	63.0%	82.0%	26.3%	56.9%
Minimum Capacity Factor	38.6%	50.3%	2.1%	0.0%

Sources: EIA 2021 (production output by source); Magness 2021, 14-15 (total capacity and capacity by type).

The demand and supply imbalance forced ERCOT to begin power outages early in the morning on February 15. For February 15 and 16, power shortages ranged between 13,000 and 20,000 MW (Magness 2021, 15). At the peak of the shortage, approximately 4.5 million consumers were reportedly cut off from power (Ball 2021).[5] Estimated demand (including load shed) fluctuated between 61,000 and 73,000 MW on February 15, between 61,000 and 74,000 MW on February 16, and between 59,000 and 68,000 MW on February 17 (Magness 2021, 15). Shortages declined throughout the day on February 17 as natural gas supply began coming back online, ending at midnight that day. The maximum outage length in February 2021 was 70.5 hours (Magness 2021, 15, 19).

Would Capacity Markets Have Helped?

It is unlikely that a capacity market would have prevented ERCOT's February 2021 power crisis. ERCOT generally operates with capacity reserve margins of approximately ten percent (Newell et al. 2018, 29-30). In contrast, RTOs with capacity markets typically operate with reserve margins between fourteen and sixteen percent (e.g., PJM 2020, 8). Increasing ERCOT's capacity margin from ten percent to sixteen percent would increase ERCOT capacity by about 4300 MW.[6] An additional 4300 MW of capacity would not have prevented the February 2021 blackout, although it could have reduced the severity of the event if it actually produced power during the crisis. Of course, adding a capacity market is not the only way for ERCOT to increase its capacity margin. If ERCOT or its regulators want to increase the ERCOT capacity margin within existing ERCOT programs, they can simply increase the size of the ORDC adder, boosting payments to generators (Wakefield 2019).

Increasing capacity, however, is not a solution well suited to the problems that caused the February 2021 crisis. Shortages of capacity did not cause the crisis. ERCOT had adequate capacity to meet demand, but much of it was unavailable due to the storm. Indeed, the real problem in the ERCOT system was a lack of natural gas supply, not a lack of electricity generation capacity. Many natural gas wells and pipelines became inoperable due to the freezing of water that is commonly produced with natural gas, and storage tanks filled with produced water could not be emptied due to icy roads (Takahashi and Blackman 2021). Indicating this scarcity, prices of natural gas soared during the 2021 crisis from their typical levels of around $3/MMBTU to $400/MMBTu in Houston and $205/MMBTu at Waha in western Texas (Baker 2021).

One of the challenges of capacity markets has been to give generators sufficient incentives to be available during periods of scarcity.[7] It is not at all clear that a capacity market with a low bid cap like those in the Northeast RTOs would have incentivized weatherization any better than the existing ERCOT system. A comparison of the incentives to produce during a crisis in the ERCOT energy-only market versus the PJM capacity market illustrates why.

Consider, for example, the incentives of a 1 MW natural gas generator with a heat rate of 10,000 BTU/kWh during a seventy-hour crisis during which the energy price hits the $9000/MWh ERCOT cap. Assume that the price of natural gas was $200/MMBTU. Since the short-run marginal cost of generation equals a generator's heat rate times the cost of natural gas, these numbers imply that the short-run marginal cost of operating the generator would be $2000/MWh. Assume that the bid cap in the ERCOT energy market would be $2000/MWh, similar to what PJM has for emergency situations.[8] This implies that the generator would just break even based on its revenues in the energy market. Also assume, however, that if there had been a capacity market in ERCOT, it would have paid $204.29/MW-day, which was the highest price in the PJM system for delivery year 2021/22 (PJM 2021, 15). Further assume that if the generator in question did not supply power during the hypothetical scarcity event, it would lose its entire capacity market revenue for the year.[9] The generator's capacity market revenues would be worth . Thus, $76,391 would represent the marginal revenue to the generator of producing power during this hypothetical crisis.[10]

In contrast, assume that the market did not have a capacity market, and instead had an offer cap of $9000/MWh, as in ERCOT. In that case, the generator's additional energy market revenues would have been worth . Even at the actual average price during the February 2019 crisis of approximately $6600/MWh (Magness 2021, 22), the ERCOT energy market would have returned an additional during the hypothetical scarcity event. Thus, the Texas market appears to offer more incentives for weatherizing to ensure availability than the Northeast RTO capacity and energy markets would provide in a similar situation.

Adopting a capacity market similar to that of the Northeast RTOs would not have prevented ERCOT's February 2021 power crisis. Indeed, a capacity market and lower price caps would provide less, not more, incentive for generators to be available during a scarcity event.

III. If Not Capacity Markets, Then What?

Thus, capacity markets would not have made a large difference in the February 2021 blackout event. A capacity market might result in more installed capacity in the ERCOT system, but without more natural gas available, the capacity would likely have largely stood idle. Any policy that attempts to address the weaknesses of the ERCOT market that were revealed by the February 2021 storm must attack the actual cause of the problem. The basic problem was that sufficient natural gas was not available for natural gas power plants to operate.

To reflect the actual harm of an extended outage, ERCOT could raise the energy market offer cap during long-duration blackouts to better represent the extremely high value of lost load during such events. Theoretically, increasing revenues to generators during scarcity events creates stronger incentives for generators to ensure production during such events—for example, by storing more natural gas supply on site. But it seems unlikely coming out of the 2021 event, in which high electricity prices had such devastating financial consequences for electricity consumers, that the Texas Public Utility Commission would allow ERCOT to increase the offer cap. It presumably would be hard to convince the Texas public that the appropriate response to a crisis in which electricity prices soared would be to let prices increase even more.

Texas and ERCOT have several other options for addressing the threat of winter blackouts outside of the market. The Railroad Commission could require natural gas producers and pipelines to winterize their equipment. This option, however, is likely to run into strong political headwinds. Alternatively, the Public

Utility Commission could adopt regulations requiring natural gas generators to store natural gas on site, especially during winter months.[11] Finally, Texas could build additional transmission lines to connect with other RTOs, as such connections are currently limited.[12]

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Footnotes

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[2] For a discussion of the ORDC, see, for example, Potomac Economics (2016, 99).

[3] In March 2021, Texas House Energy Resources Committee Chairman Chris Paddie introduced Texas House Bill 4378, which would establish a capacity market for ERCOT. H.B. No. 4378, 87th Leg. (Tex. 2021).

[4] Although unusually cold, the storm's temperatures were not unprecedented. Historical weather data shows that other events in 1951, 1983, and 1989 were of greater or similar severity (Doss-Gollin et al. 2021).

[5] Other sources indicate the number may have been much higher. Magness implies that at the peak of the crisis, ERCOT was unable to supply 26 percent of its demand, and that ERCOT serves 26 million customers (Magness 2021, 4, 15). In turn this might imply that 6.7 million people lost power during the crisis.

[6] This estimate reflects actually available capacity, known as unforced capacity. The equivalent quantity of nameplate capacity, known as installed capacity, would be greater to account for outages and intermittency. The difference between unforced and installed capacity is especially large for intermittent generation sources.

[7] For discussion of the challenge in the ISO New England context, see FERC (2014) and ISO New England (2014). In this system, generators lose capacity revenues if they do not perform during scarcity hours. The actual loss in revenue for non-performance depends on the number of hours of non-performance during scarcity events as compared with the total number of expected hours of scarcity. PJM's capacity market performance incentive system is largely based on that of ISO New England. NYISO does not have a comparable enforcement mechanism.

[8] The PJM emergency bid cap is $2000/MWh (FERC 2016).

[9] This is consistent with the way the ISO New England performance incentive policy works , because the duration of the hypothesized seventy-hour scarcity event would exceed the annual expected scarcity hours.

[10] It is possible that an RTO could set a high offer cap in the energy market and also adopt a capacity market, although no system operator has pursued that strategy.

[11] Freeman et al. (2021) explore this question in the context of ISO New England.

[12] ERCOT now has approximately 1090 MW of import transmission capacity (FERC and NERC Staff 2011, 25).