Omaha Public Power District

OPPD BOARD OF DIRECTORS

BOARD MEETING MINUTES

March 19, 2026

The regular meeting of the Board of Directors of the Omaha Public Power District ("OPPD" or "District") was held on March 19, at 5:00 p.m. at the Omaha Douglas Civic Center, 1819 Farnam Street, 2nd Floor Legislative Chamber, Omaha, Nebraska and via WebEx audio and video conference.

Joining in person were Directors A. E. Bogner, M. J. Cavanaugh, M. R. Core, S. E. Howard, C. C. Moody, M. G. Spurgeon and E. H. Williams. J. L. Hudson was absent. Also present were L. J. Fernandez, President and Chief Executive Officer, and Messr. S. M. Bruckner of the Fraser Stryker law firm, General Counsel for the District, E. H. Lane, Sr. Board Operations Specialist, and other members of the OPPD Board meeting logistics support staff. Chair M. R. Core presided, and E. H. Lane recorded the minutes. Members of the executive leadership team joining in person included K. W. Brown, S. M. Focht, C. V. Fleener, G. M. Langel, and T. R. Via.

Board Agenda Item 1: Chair Opening Statement

Chair Core gave a brief opening statement, including reminders for using the WebEx audio and video conferencing platform.

Board Agenda Item 2: Safety Briefing

J. Clark, Manager, Protective Services, provided safety reminders.

Board Agenda Item 3: Guidelines for Participation

Chair Core then presented the guidelines for the conduct of the meeting and instructions on the public comment process using WebEx audio and video conferencing features.

Board Agenda Item 4: Roll Call

Ms. Lane took roll call of the Board. All members were present via WebEx, except J. L. Hudson.

Board Agenda Item 5: Announcement regarding public notice of meeting

Ms. Lane read the following:

> *"Notice of the time and place of this meeting was publicized by notifying the area news media; by publicizing same in the Omaha World Herald and Nebraska Press Association, OPPD Outlets newsletter, oppd.com and social media; by displaying such notice on the first level of the OPPD administrative offices; and by e-mailing such notice to each of the District's Directors on March 13, 2026.*

A copy of the proposed agenda for this meeting has been maintained, on a current basis, and is readily available for public inspection in the office of the District's Corporate Secretary.

Additionally, a copy of the Open Meetings Act is available for inspection on oppd.com."

Board Consent Action Items:

6. Approval of the February 2026 Meeting Minutes, and March 19, 2026 Agenda
7. SD-1: Strategic Foundation Monitoring Report – Resolution No. 6751
8. Sale of Property for Public Infrastructure (Sub 3454 Sarpy County) – Resolution No. 6752

It was moved and seconded that the Board approve the consent action items.

Chair Core noted the Board discussed the action items during the All Committees meeting held on Tuesday, March 17.

Chair Core then asked for public comments in person and on WebEx. There were no comments.

Thereafter, the vote was recorded as follows: Bogner – Yes; Cavanaugh – Yes; Core – Yes; Howard – Yes; Hudson – Absent; Moody – Yes; Spurgeon – Yes; Williams – Yes. The motion carried (7-0).

Board Discussion Action Items

9. Vice President, General Counsel - Appointment and Compensation Approval – Resolution No. 6753

Director Spurgeon moved to approve the discussion action item, and it was seconded by Director Cavanaugh. Chair Core asked for Board member questions or comments. CEO Fernandez provided comments on Mr. Fischer's background.

Chair Core then asked for public comment. There were none.

Chair Core asked for comments from the Board. There were no additional comments.

Thereafter, the vote was recorded as follows: Bogner – Yes; Cavanaugh – Yes; Core – Yes; Howard – Yes; Hudson – Absent; Moody – Yes; Spurgeon – Yes; Williams – Yes. The motion carried (7-0).

Chair Core invited Mr. Fischer to provide comments on his appointment as Vice President, General Counsel.

Board Discussion Action Items

10. Honoring the Service of Dennis D. Jorgensen – Resolution No. 6754

Director Spurgeon moved to approve the discussion action item, and it was seconded by Director Moody. Chair Core asked for Board member questions or comments. Director Moody, Director Cavanaugh and S. M. Bruckner provided comments in support of the resolution and reflected on Mr. Jorgensen's life and long tenure as a board member and his service to OPPD.

Chair Core then asked for public comment. There were none.

Chair Core asked for comments from the Board. There were no additional comments.

Thereafter, the vote was recorded as follows: Bogner – Yes; Cavanaugh – Yes; Core – Yes; Howard – Yes; Hudson – Absent; Moody – Yes; Spurgeon – Yes; Williams – Yes. The motion carried (7-0).

Board Agenda Item 10: President's Report

CEO Fernandez next presented the following information:

- February 2026 Baseload Generation
- February 2026 Balancing Generation
- February 2026 Renewables
- Assisting Customers
- Heat the Streets Run and Walk for Warmth
- Integrated System Plan
- In Memoriam – Larry McGrew

Board Agenda Item 11: Opportunity for comment on other items of District Business

Chair Core asked for comments from the public in the room. There were five comments.

David Begley, 4611 S. 96th St, provided comments on energy for Stratcom, and wind and solar projects in Nebraska.

Anthony Rogers Wright, 3010 Lincoln Boulevard, representing Black Alliance for Peace, provided comments on the health risk assessment for North Omaha, data centers, and environmental justice.

Joshua Monaco, representing Socialism and Liberation party, provided comments on data centers and coal plants in Nebraska.

Melanie Williams, 16022 Orchard Circle, provided comments on data centers and the North Omaha Station.

Calvin Gravy, 7114 Jones Circle, representing Omaha Cares Coalition, provided comments on climate change and data centers.

Chair Core asked for comments from the public via WebEx. There were three comments.

Vern Carlson, 800 Buckboard Blvd.,provided comments on data centers and LB1261.

David Corbin, 1002 N. 49th St, representing the Missouri Valley Sierra Club, provided comments on a health monitor in North Omaha.

John Pollack, 1412 N. 35th Street, Omaha, North Omaha Station and provided a weather update.

There were no additional comments from the public.

There being no further business, the meeting adjourned at 6:00 p.m.

DocuSigned by:
Cliff Fleener
6935561361B2412...

C. V. Fleener
Vice President – Sustainability and Environmental Affairs

DocuSigned by:
Erin Lane
965CE2363A0A42C...

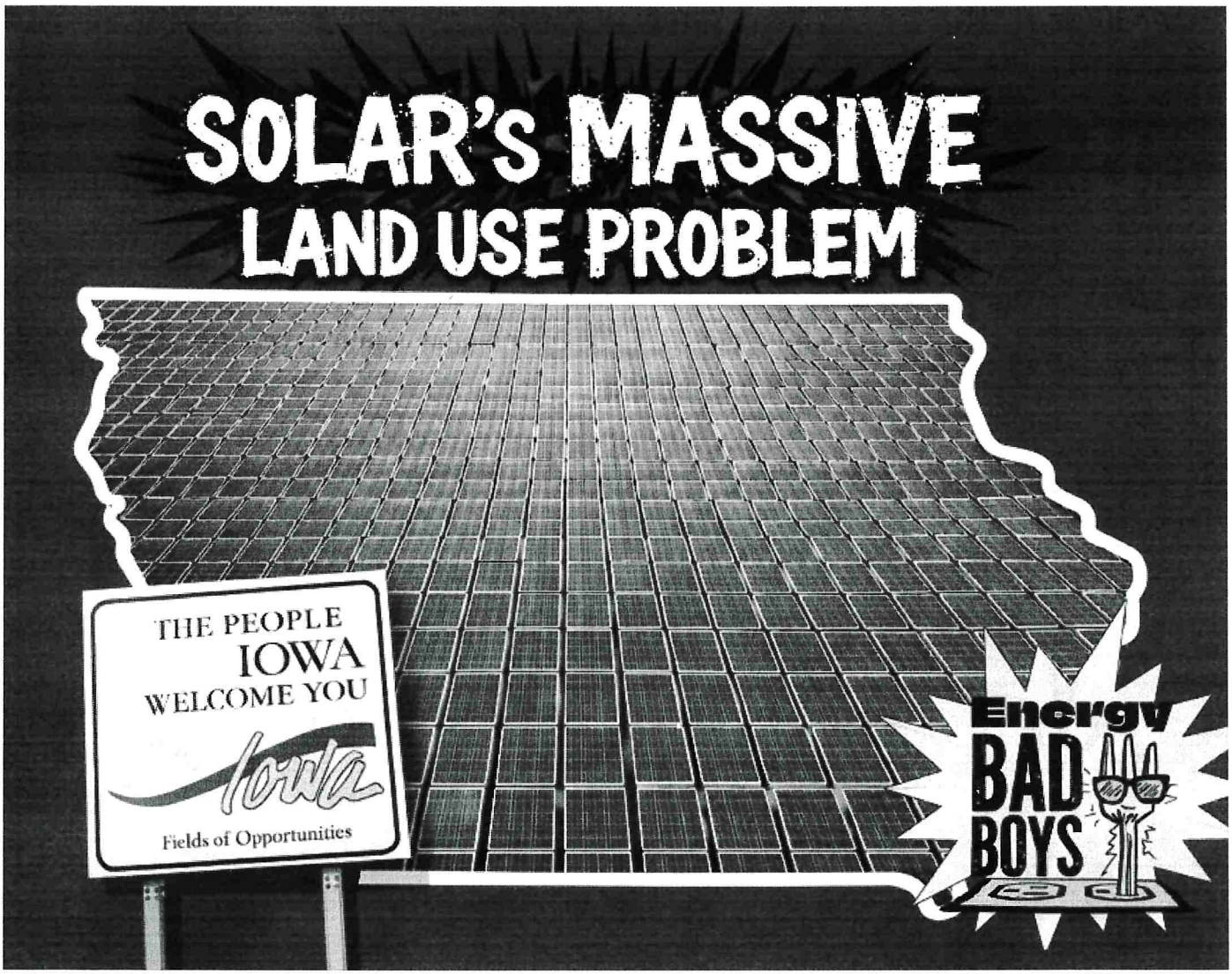
E. H. Lane
Sr. Board Operations Specialist

Solar's Land Use Problem Is Much Worse Than You Think

You won't believe these numbers...

ENERGY BAD BOYS AND MITCH ROLLING
FEB 14, 2026

"Land, land, land, see snatch." Hedley Lamarr in *Blazing Saddles*



Most public discussions about solar focus on energy production, but power systems are built around reliability during peak demand. Once you look at the grid through lens of accredited capacity—that is, capacity that can be relied upon during peak demand—instead of annual energy, the land requirements for different technologie look radically different.

This is the energy vs. capacity distinction that most solar land-use debates miss.

Last September, we were retained by Cerro Gordo County, Iowa, to provide expert witness testimony on a proposed 500-megawatt (MW) solar facility, the River City Energy Project. If you are interested in retaining us for a utility proceeding, please reach out to us by clicking here.

As part of the proceedings in the Generating Certificate Utility (GCU) docket GCU 2025-0004, we were responsible for evaluating the land-use and economic impacts c solar in Cerro Gordo County and how it would compare to a new combined-cycle (C natural gas (CC) facility.

For today's analysis, we'll focus on the land-use impacts of solar; they are worse tha you think.

Long story short, **matching the accredited capacity of one natural gas plant sitting 58 acres of land with solar in 2030 would require over 105,792 acres of solar panel roughly 29% of the total land area of Cerro Gordo County.**

The River City Energy Project

The River City Energy Project is a 500 megawatt (MW) solar farm proposed by Rang Power in Cerro Gordo County, Iowa. If approved, the total project site would be 2,8 acres, most of it on farmland, equating to an average of 5.8 acres per MW of installe capacity.

In contrast, the Emery Generating Station, a nearby CC natural gas plant also locat in Cerro Gordo County, has a total rated capacity of 602.8 MW and sits on a total of around 58 acres. Including the power plant and the parking lot, land use for this CC plant equates to 0.096 acres per MW of installed capacity.

This means the proposed Ranger Power solar facility would require 60 times mor land per MW than a CC natural gas plant of equal size.

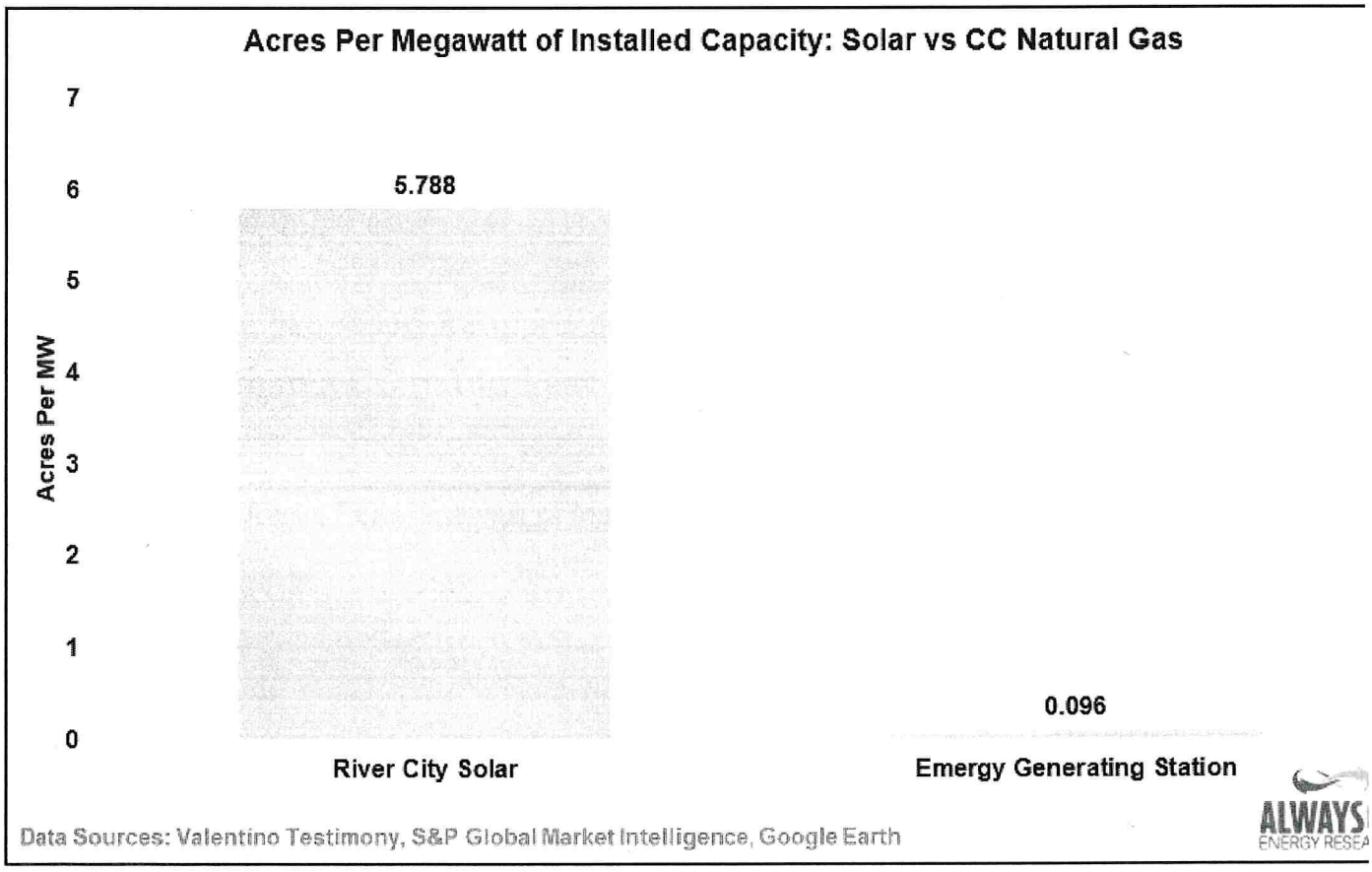
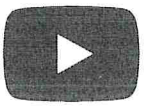


Figure 1. The proposed Ranger Power facility would consume significantly more land than a new combined cycle natural gas plant, such as the Emery Generating Station.

The disparities in land use become more evident when the reliability and resource adequacy attributes of each resource are considered.

Today's Key Word is Capacity Value. Do You Hav Any?

evaluation day tony perkis



In testimony in favor of the proposed solar project, River City Witness Waylon Brov stated the Ranger Power project is expected to garner a "about 50 percent capacity credit in spring, summer, and fall," from the Midcontinent Independent System Operator ("MISO").

However, Mr. Brown's stated values are not at all reflective of the projected capacity values that will be attributed to wind and solar in the coming years because MISO i revising its capacity accreditation methods to better reflect the reliability contributions of all resources on its system during periods where the system is mos likely to experience loss of load hours.

The shift away from Effective Load Carrying Capacity ("ELCC") to Direct Loss of L ("DLOL") accreditation will have important implications for the reliability metrics

assessed for each resource class.

Table 1 shows the indicative seasonal capacity accreditations that solar facilities would receive in the 2025-2026 planning year using DLOL, and the DLOL assumpti used in 2030, 2033, and 2043 in the MISO 2024 Regional Resource Assessment and Technical Appendix.

SEASONAL CAPACITY ACCREDITATION FOR SOLAR USING DLOL METHODOLOGY					
Planning Year	**Summer**	**Fall**	**Spring**	**Winter**	**Annual Average**
2025-2026	45%	28%	28%	19%	30%
2030	4%	2%	2%	1%	2.25%
2033	4%	3%	2%	0%	2.25%
2043	2%	1%	1%	0%	1%

Table 1. Based on the DLOL methodology, the indicative summer capacity value for solar resources would fall from 45% in the 2025-26 Planning Year to 4% in 2030. Annual average capacity values would fall from 30% to 2.25% in that timeframe.

MISO documents also show the projected capacity accreditations of combined cycl natural gas facilities using DLOL during the same period. Annual average capacity accreditations are expected to be 86% in the 2025-2026 Planning Year, 82% in 2030, in 2033, and 81% in 2043 (See Table 2).

SEASONAL CAPACITY ACCREDITATION FOR COMBINED CYLE NATURAL GAS USING DLOL METHODOLOGY					
Planning Year	**Summer**	**Fall**	**Winter**	**Spring**	**Annual Avera**
2025-2026	95%	92%	77%	78%	86%
2030	89%	79%	92%	69%	82%
2033	87%	78%	93%	65%	81%
2043	88%	78%	92%	65%	81%

Table 2. The annual average capacity value for natural gas-fired power plants is expected to decline from 86% in the 2025-2026 Planning Year to 81% in 2043.

Comparing the proposed Ranger Power project with a new 500 MW combined cycl natural gas facility yields substantial differences in the accredited capacity awardec each 500 MW facility. Figure 2 adjusts the total installed capacity of each resource l its annual average capacity value to determine the annual average accredited capac each project would provide to the MISO system.

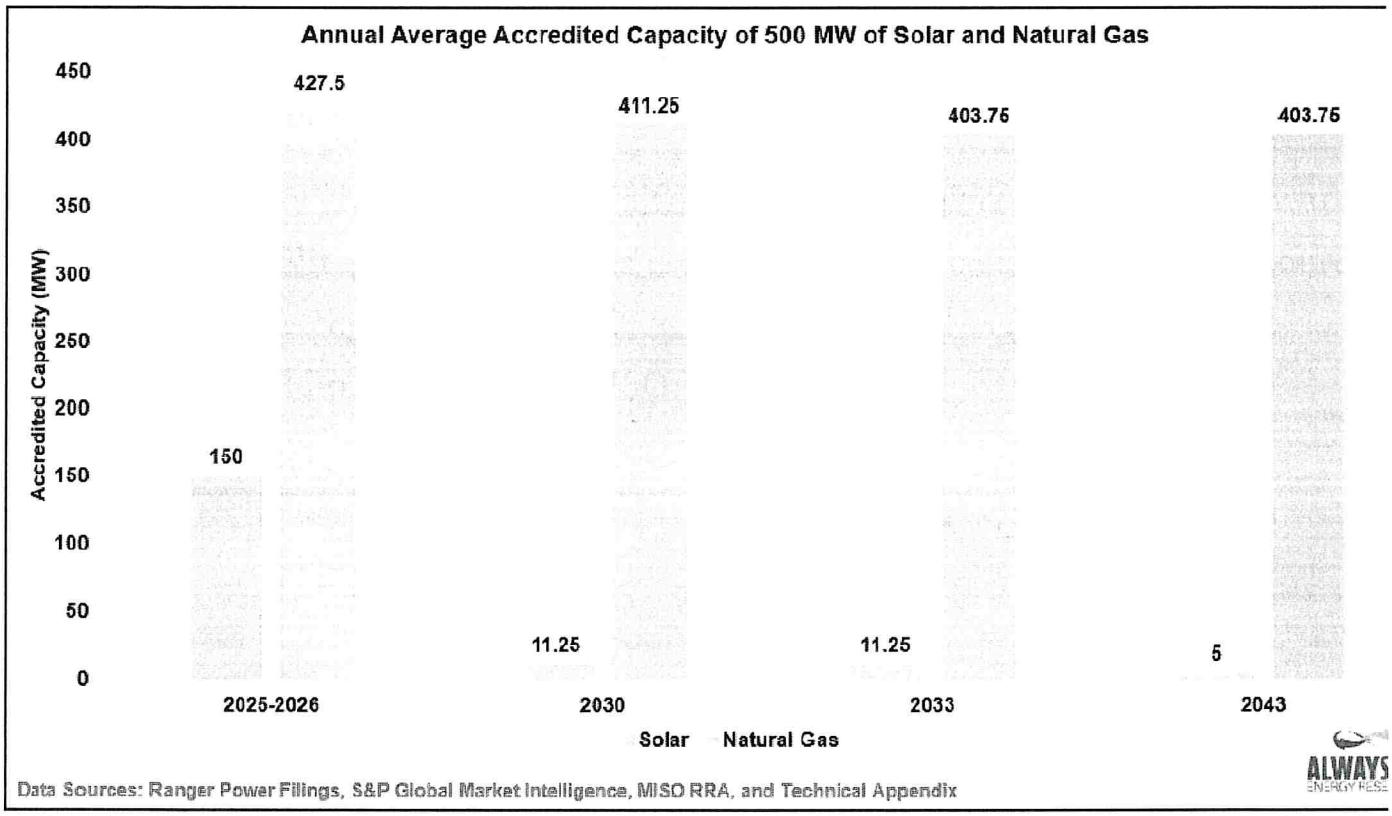


Figure 2. Applying the capacity value of each resource to the 500 MW installed capacity yields the accredited capacity of each resource.

By dividing the total acreage of the proposed Ranger Power project and a new natu gas plant by its accredited capacity from Figure 2, we can determine the number of acres needed to provide one MW of firm accredited capacity to the MISO system in each Planning Year, shown in Table 3.

ACRES NEEDED FOR PER MW OF ACCREDITED CAPACITY FOR RANGER POWER VS NATURAL GAS USING DLOL (DIRECT AND INDIRECT)		
Planning Year	**Solar**	**Natural Gas**
2025-2026	19.29	0.14
2030	257.24	0.14
2033	257.24	0.14
2043	578.80	0.14

Table 3. This stable shows the number of acres of land that would be needed to host one MW of accredited capacity with solar or natural gas in four illustrative planning years.

The low capacity value attributed to solar using the DLOL metric would necessita 19.29 acres of solar panels for one MW of accredited capacity in the 2025-2026 planning year, compared to 0.14 acres for a combined cycle natural gas plant. In 2030 and 2033, it would require 257.24 acres of solar panels for one MW of accredited capacity, growing to 578.80 acres in 2043.

In comparison, natural gas would require 0.14 acres, 0.14, and 0.14 acres in 2030, 2033, and 2043, respectively.

In the interest of maximizing the efficiency of land used for electricity generation, i illustrative to compare the acreage needed to provide the same capacity value of the proposed Ranger Power facility and a new natural gas plant.

Figure 2 above shows the accredited capacity a new gas plant could expect to receiv under the DLOL accreditation metric. Table 4 below displays the number of solar acres needed to match the capacity value of the hypothetical combined cycle natura gas plant in each illustrative planning year and compares this total to the land area Cerro Gordo County.

ACRES OF SOLAR NEEDED TO MATCH THE ACCREDITED CAPACITY OF A NEW NATURAL GAS PLANT					
	Solar Acres per 1 MW of Accredited Capacity	**Natural Gas Accredited Capacity**	**Solar Acres Need to Match Gas Accredited Capacity**	**Total Acres, Cerro Gordo County**	**Percentage Cerro Gord County Need for Solar**
2025-2026	19.3	427.5	8,248	368,000	2%
2030	257.2	411.25	105,792	368,000	29%
2033	257.2	403.75	103,862	368,000	28%
2043	578.8	403.75	233,691	368,000	64%

Table 4. The relatively low capacity value of solar necessitates the use of large acreages to produce one MW of accredited capacity.

Matching the accredited capacity of one natural gas plant with solar in 2030 would require over 105,792 acres of solar panels, roughly 29% of the total land area of Cerr Gordo County.

Now, Let's Do All of Iowa

According to MISO's Planning Resource Auction results for the 2025/26 Planning Year, Load Zone 3 covers basically Iowa, slivers of Southern Minnesota, and a tiny p of Northern Illinois.

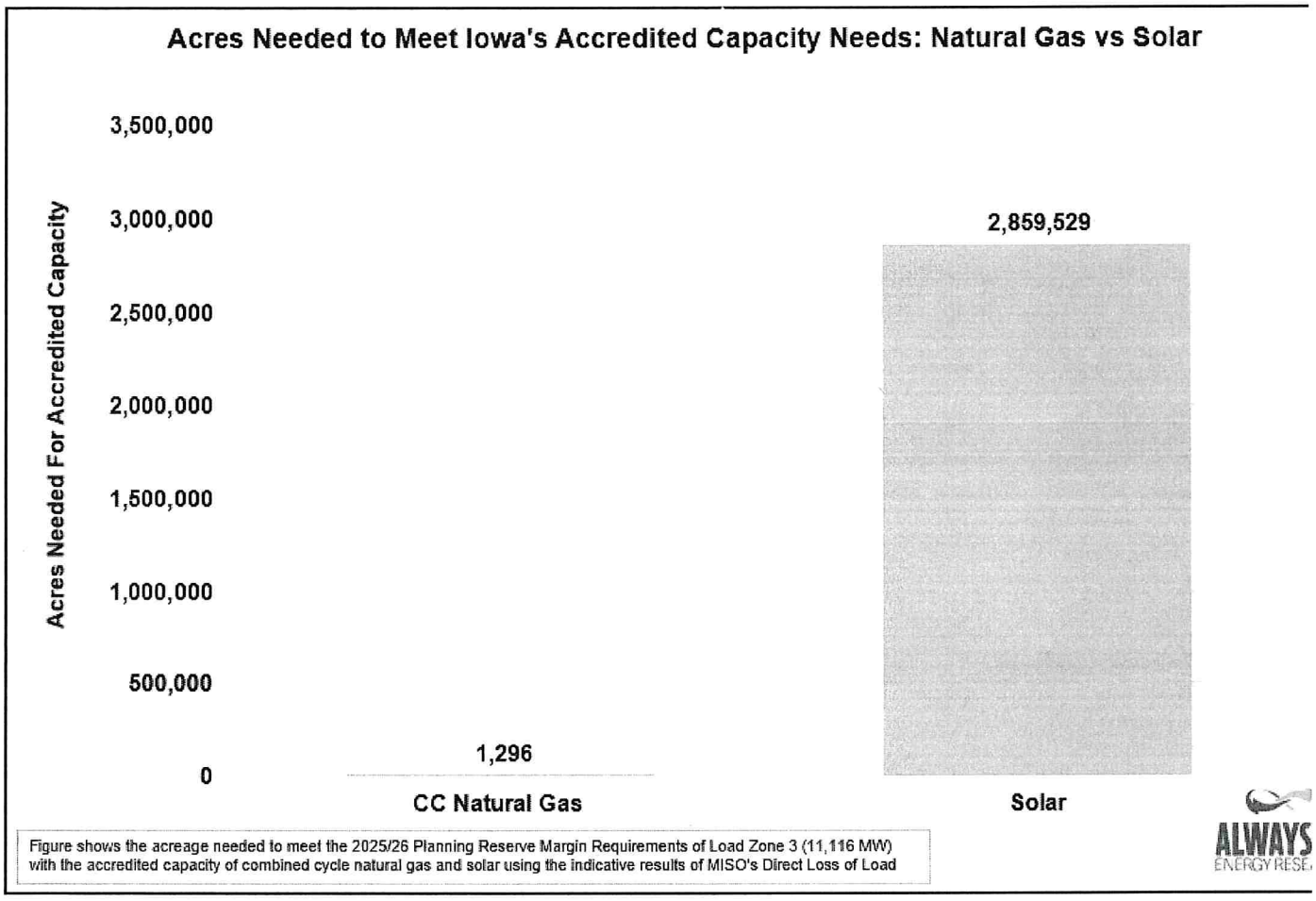
According to the MISO documents, this region has a peak summer planning reserv margin requirement of 11,116 MW.

If we were to meet this with natural gas, it would require 1,296 acres of land, which 0.0036 percent of all the land in Iowa. In contrast, meeting this capacity obligation with solar would require 2.86 *million* acres, or roughly 8 percent of the state's total landmass.

Land Needed to Power Iowa's Capacity Needs		
	CC Natural Gas	Solar
Needed Accredited Capacity (MW)	11,116.00	11,116.00
2030 Capacity Value	82.25%	2.25%
Capacity Needed	13,515	494,044
Acres Per MW	0.096	5.79
Acres for Accredited Capacity	1,296	2,859,529
Total Acres of Iowa	35,860,480	35,860,480
Percent Needed	0.0036%	7.97%
Solar Requires ~2,200× More Land		2,207.02

Table 5. Land needed to meet Iowa's capacity obligations.

For the math majors at home, this means it would take 2,207 times more land to me Iowa's capacity needs with solar than with natural gas. Just for fun, let's look at hov this looks in a bar chart.



The most obvious retort to the information in this graph is "no one is going to depe on solar to provide all of the capacity needed to meet your peak demand and reserv margin."

However, as we saw in Witness Brown's testimony, solar advocates have been crowi about the capacity value of the resources without acknowledging that it is about to drive over a cliff under DLOL, rendering it essentially useless as a capacity resourc

Conclusion

These land use implications are not unique to Iowa, they are a structural feature of how modern power systems are planned. Resources that produce lots of energy but little firm capacity can look efficient on a megawatt-hour basis while requiring enormous physical scale to meet reliability requirements.

Solar can provide *energy* to the power system, but it is becoming increasingly clear t its value as a capacity resource is diminishing quickly. This has obvious implicatior for reliability, but it will also impact utility planning and land use issues that are playing out at utility commissions across the country.

Fear not, your tireless *Energy Bad Boys* will continue applying this same capacity-ba framework to other states and technologies in upcoming analyses. All we ask in ret is for you to ***share, subscribe, and give us all of your money.***

Energy Bad Boys is a reader-supported publication. To receive new posts and support our work, consider becoming a free or paid subscriber.

High electricity rates a regional, not national, trend – study S&P Global

"A widely reported increase in average retail rates in the US has been interpreted a: indicative of a broader, national trend. This is not the case," Charles River Associat or CRA, said in the report.

"Rather, in a few states and regions, rates have increased rapidly, putting upward pressure on the national average. Retail electric rates have generally been stable in other regions," the firm said.

NY Democrats propose data center development moratorium S&P Global

Is New York even serious anymore?

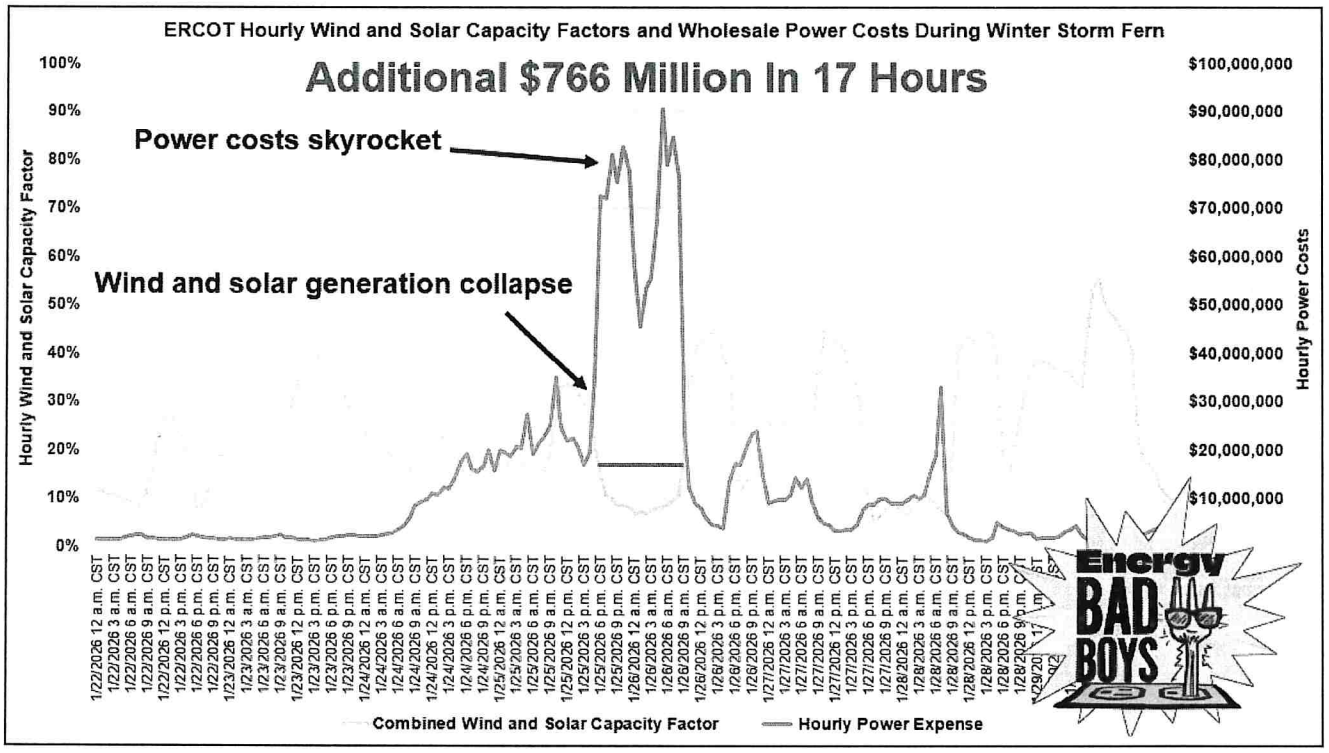
States step up efforts to permit renewables ahead of US tax credit deadline S&P Global

Blue states rush to help themselves to your tax dollars

"Oregon's executive and legislative actions follow moves in Colorado, California, N York, New Jersey and Maine" to speed up the construction of wind and solar projec to qualify for federal subsidies.

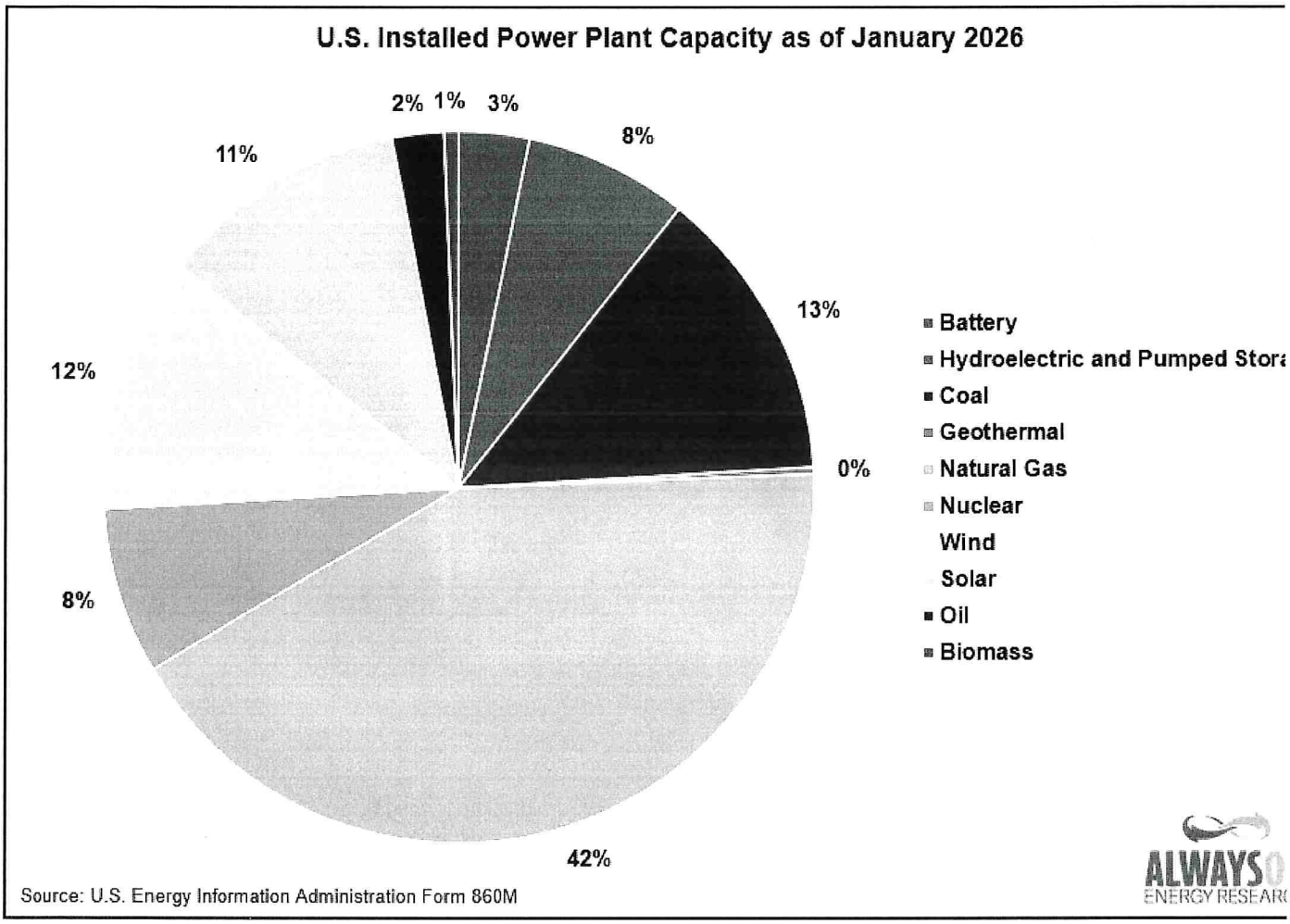
Disappearing Wind and Solar Cost Texans $766 Million Extra in 17 Hours

Everything's bigger in Texas, including the power price spikes.



In the wake of Winter Storm Fern, the U.S. Department of Energy correctly noted t it was America's thermal fleet that carried the day, as coal, natural gas, nuclear, and for our friends in New England provided 86 percent of the power generated during peak of the storm, while wind and solar generated just 8 percent and 2 percent, respectively.

This is despite the fact that U.S. Energy Information Administration (EIA) data sho wind and solar constituted roughly 23 of the total installed capacity on the grid in January, meaning they punched below their weight when the grid was stressed.



With egg on their faces, the American Clean Power Association (APCA), the top lobbying arm of the wind and solar industry, hastily started up the spin machine for damage control. As a result, it issued this website claiming that wind and solar save consumers more than $2 billion during the winter weather event, including $200 million in savings in the Electric Reliability Council of Texas (ERCOT) Region

However, ACPA doesn't disclose *how* it calculated those figures, and it didn't respor to our emails requesting more information, so we did a little analysis of our own. W found that it is exceedingly unlikely that wind and solar saved Texas *any money.*

In fact, our analysis found that wind and solar disappeared just when they were nee most, costing Texans an additional $766 million in wholesale power costs in just 17 hours.

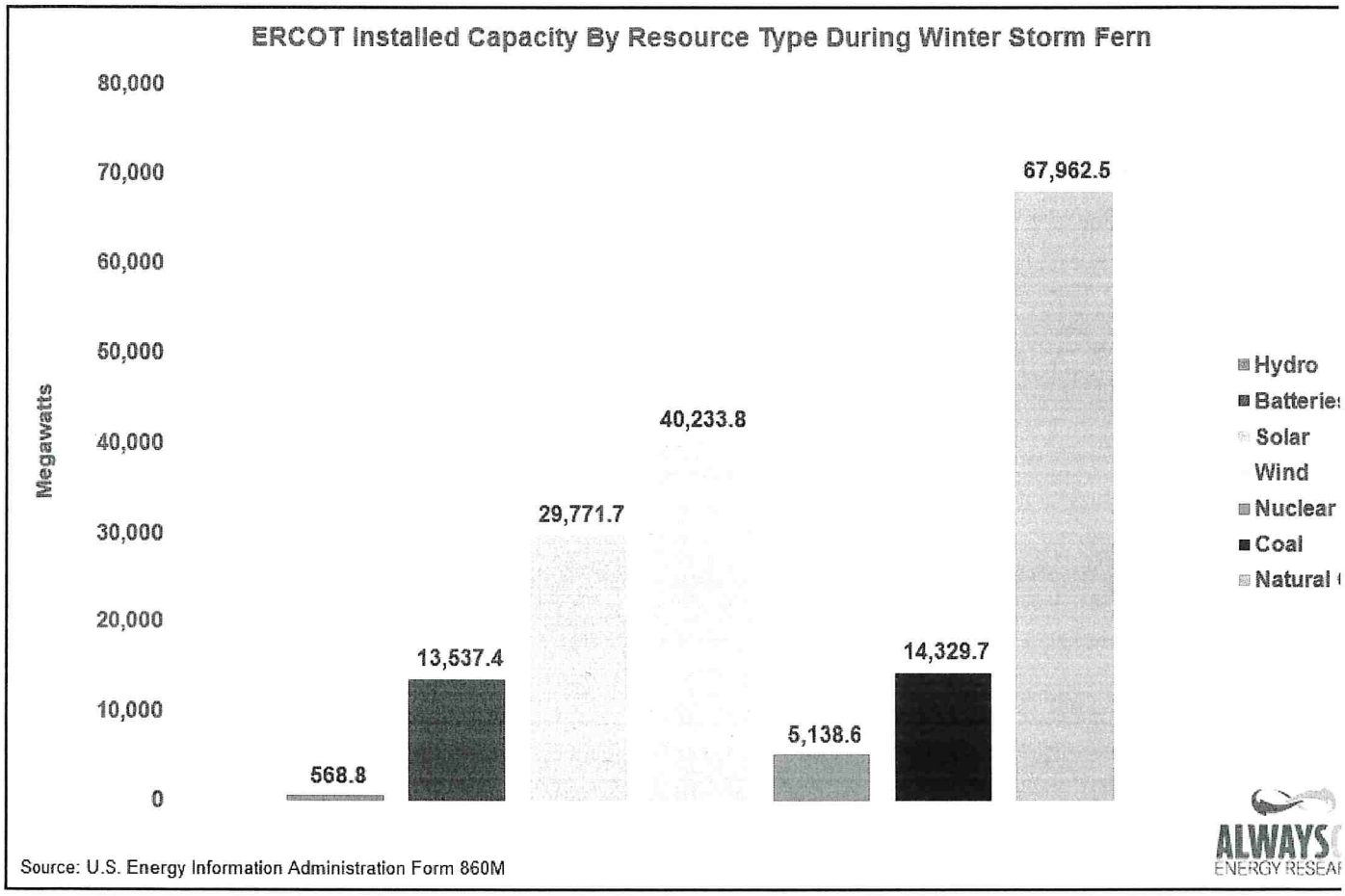
To understand why, it helps to know some background.

ERCOT's Generation Mix

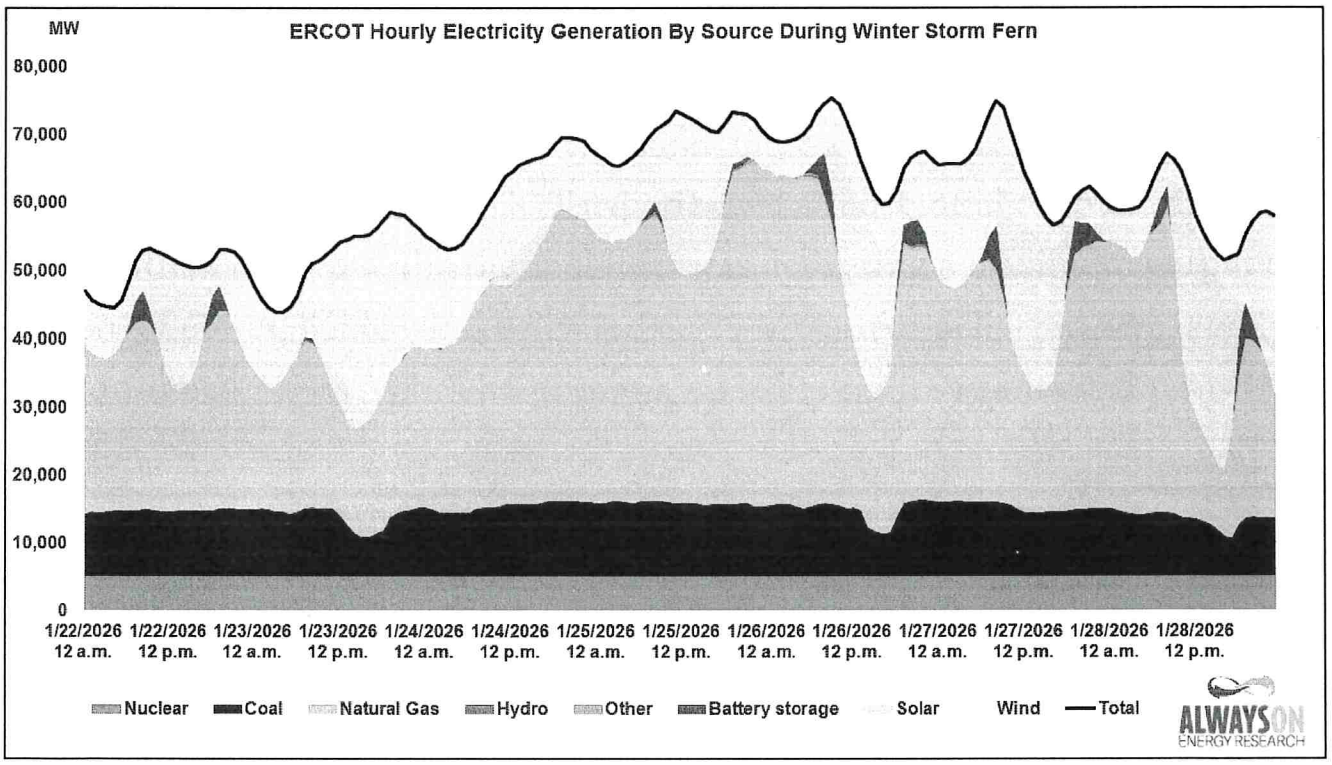
For many years, ERCOT has become increasingly dependent weather-dependent resources, particularly wind energy, for meeting peak demand.

As we have noted on several occasions, ERCOT hasn't added any net thermal capac since 2013, and the amount of thermal generation on the system has decreased sinc 2016 despite the fact that peak demand has grown by over 12,000 megawatts (MW), by over 17 percent in the last ten years.

According to EIA Form 860M data, ERCOT had 171,542 MW of total installed capa on its system as of December 2025, with 87,430 MW of thermal capacity and 83,542 MW of wind, solar, and battery storage, as shown in the graph below.



On paper, this should have been more than enough capacity to weather Winter Stor Fern without a massive spike in prices, and for some of the time it didn't. However, around 5 pm on January 25th, ERCOT experienced a substantial drop in wind and solar generation. At 10 pm, the thermal fleet was delivering a maximum output of 66,087 MW of power, while wind delivered 6,025 MW, solar delivered zero, and batt storage consumed 319 MW for charging, which led to tight system conditions.



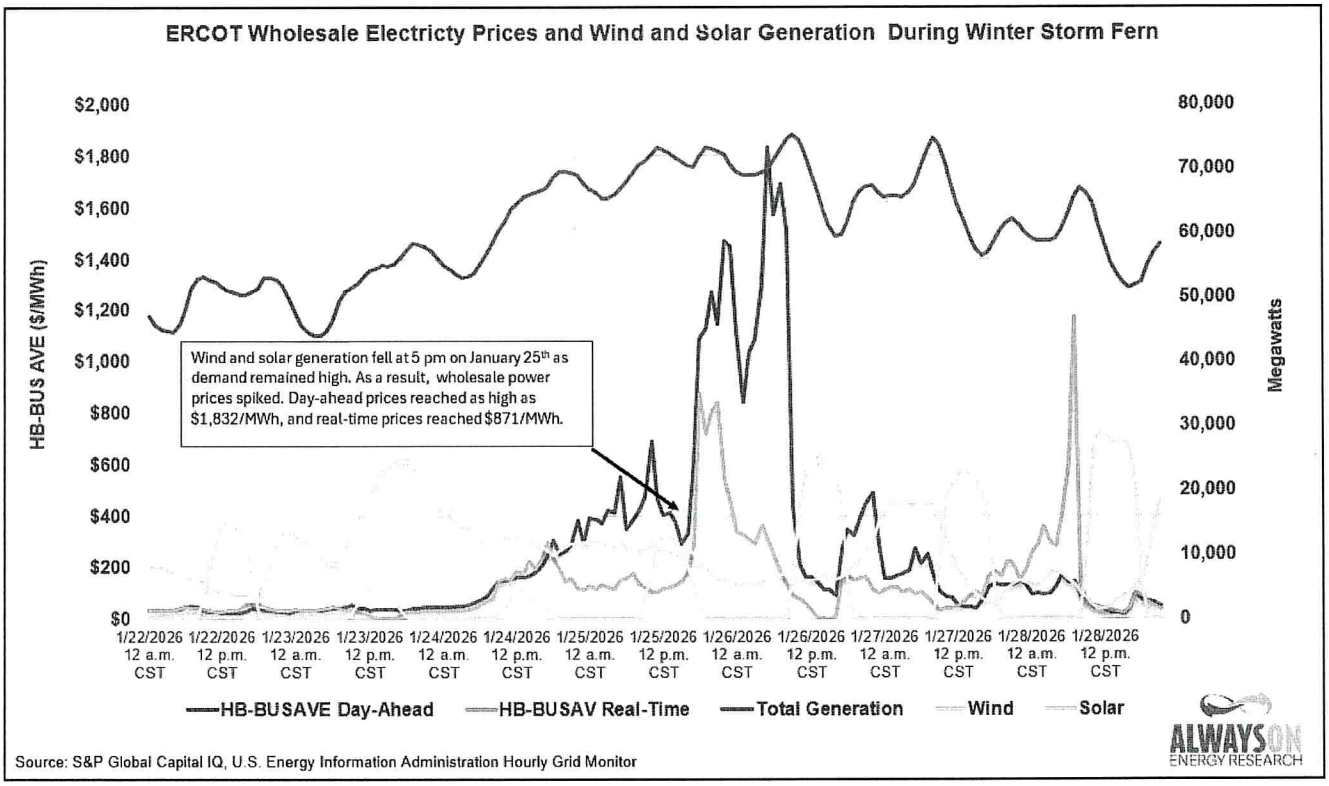
At 10 pm, the thermal fleet was generating 66,086 MW while wind, solar, and battery storage were delivering just 5,706 MW.

Wholesale Power Prices: Ready for Liftoff

These tight system conditions led to a massive spike in power prices in ERCOT.

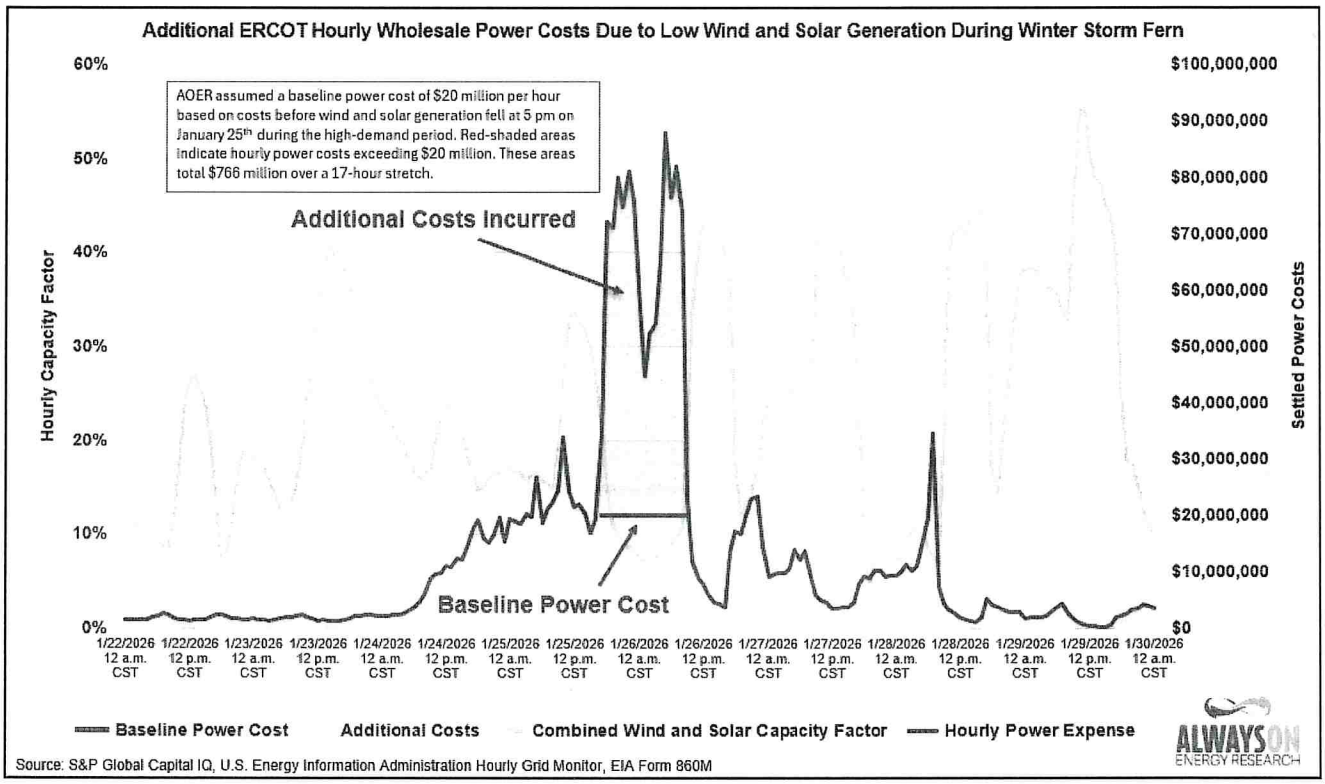
Day-ahead and real-time wholesale price data from S&P Global data show prices spiked in concert with wind and solar's disappearing act. For instance, notice in the graph below that while prices (dark green line for Day Ahead, green line for Real-Time) increased slightly with the rise in demand, they didn't spike until electricity production from wind and solar both plummeted.

Day-ahead prices reached a high of $1,832 per MWh, and real-time prices reached $ per MWh, resulting in massive power costs for Texas families and businesses.



ERCOT data indicate that approximately 62.5 percent of all MWhs purchased in January of 2026 were bought on the day-ahead market, and 37.25 percent on the rea time market. Using this split, we were able to create a blended hourly wholesale po cost for consumers and determine the additional costs to consumers compared to wholesale power costs before the variable energy sources pulled their vanishing act

The graph below shows the combined hourly wind and solar capacity factor and the settled energy cost in ERCOT during Winter Storm Fern. It also shows the additior power costs, shaded in light red, incurred as a result of the drop in wind and solar generation, relative to a $20 million-per-hour power baseline cost, shown by the rec line. **The total additional cost of the light red areas is $766 million over 17 hours.**



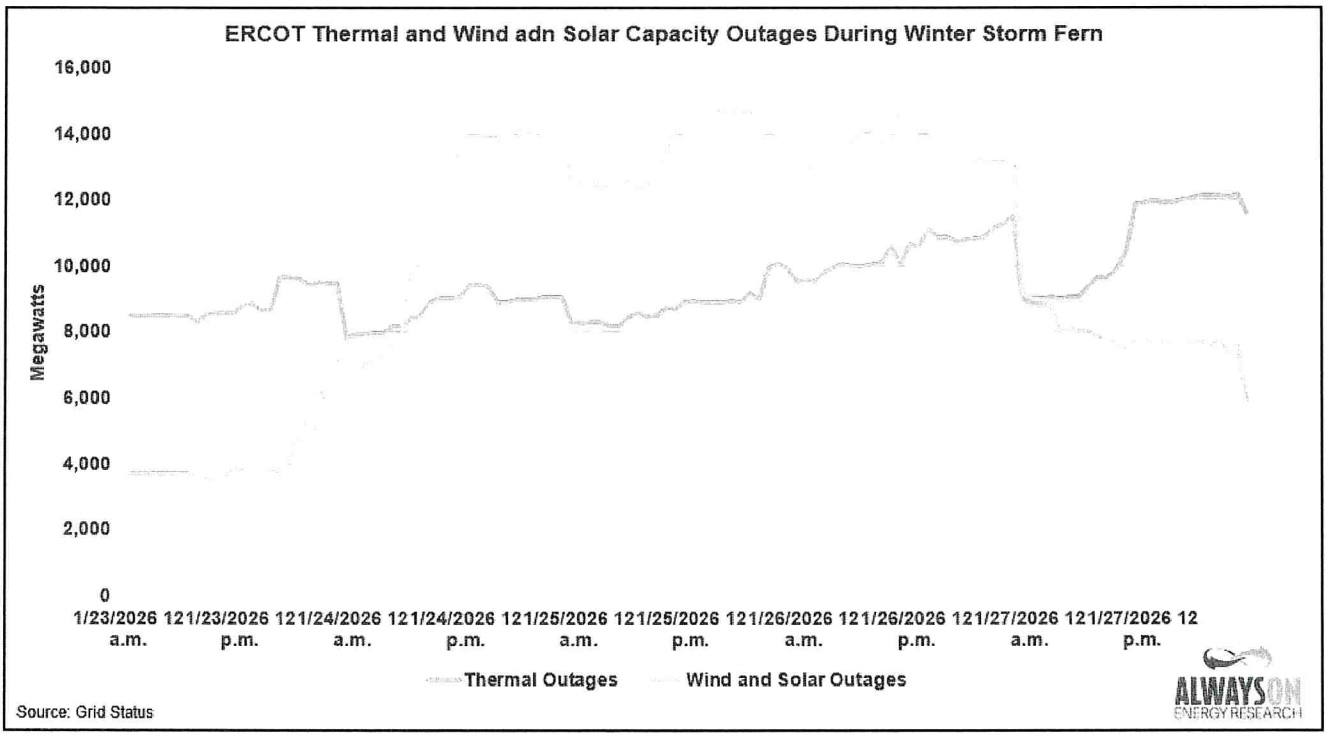
Our analysis used $20 million as the baseline because it was the approximate cost o power at 4 pm on January 25th, the hour just before wind and solar output dropped during the high-demand period.

The Anatomy of a Price Spike: Why Did They Rise So High?

Ultimately, the price increase was the result of high demand and inadequate supply

Data from GridStatus shows outages for thermal units, wind, and solar during Wint Storm Fern. Wind and solar had lower initial outages, but outages spiked on Januar 24th as the cold front moved in.

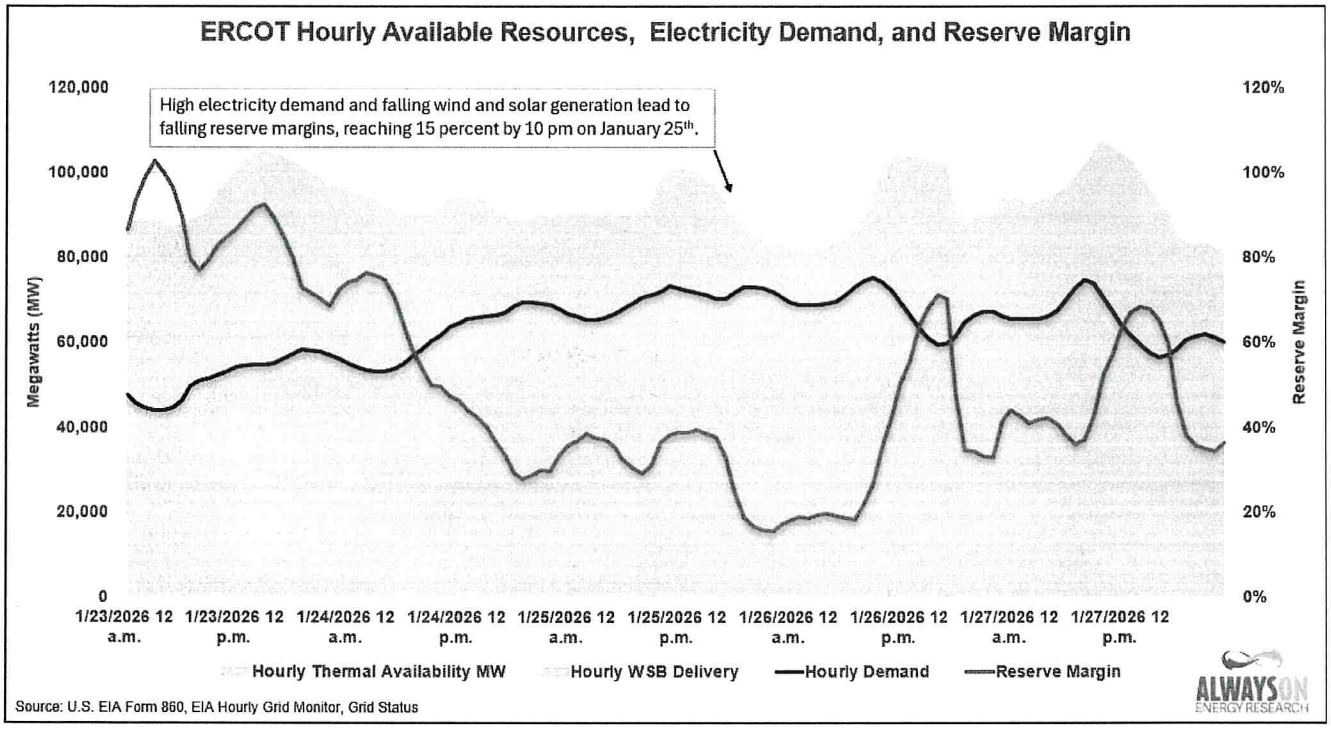
In contrast, thermal facilities had relatively low outage rates, with availability rangi from 88 to 90 percent during the price spike event, which lasted from the evening o January 25th through the morning of January 26th, then falling to 87 percent on January 27th.



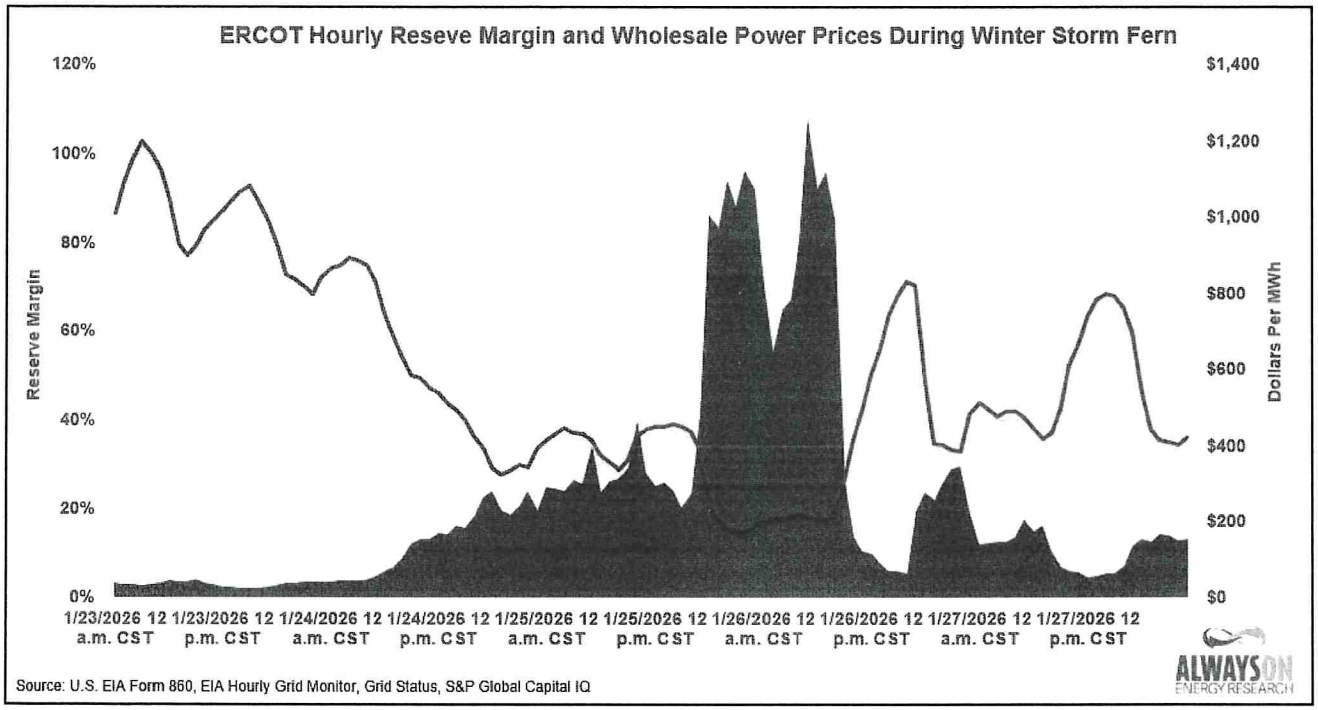
The outages reduced ERCOT's reserve margin, which we define here as the amount installed thermal capacity on the system, minus outages, plus intermittent generati available to meet demand during any given hour during the storm. We defined the reserve margin this way because wind and solar can (and did) fail to show up due to lack of wind or sunlight, even if they are not technically on outage.

The graph below shows the amount of thermal generation available to meet peak demand, the amount of power provided by wind, solar, and battery storage, and the hourly demand on ERCOT from January 23rd through the 27th.

The red line shows the reserve margin, which dips from over 100 percent on Januar 23rd, when demand was lower, and wind, solar, and storage were able to deliver mo power to the grid, down to just 15 percent starting at 5 pm on January 25th.



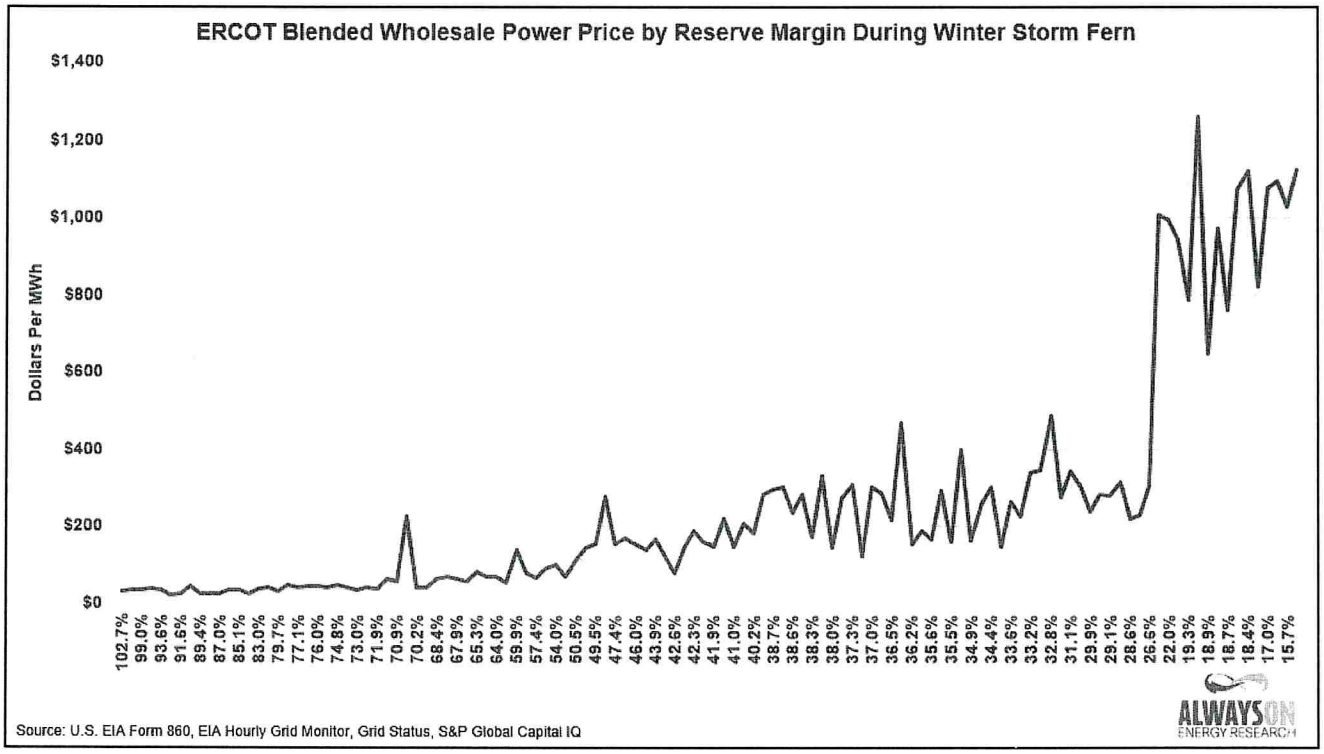
Unsurprisingly, the falling reserve margin is highly correlated with rising electricit prices. In fact, in an energy-only market like ERCOT, where the grid operator does make reliability payments to dispatchable generators to be available during periods high stress, like winter storms, high prices are the primary mechanism for keeping reliable plants online, as they capture huge amounts of revenue during these "scarc events."



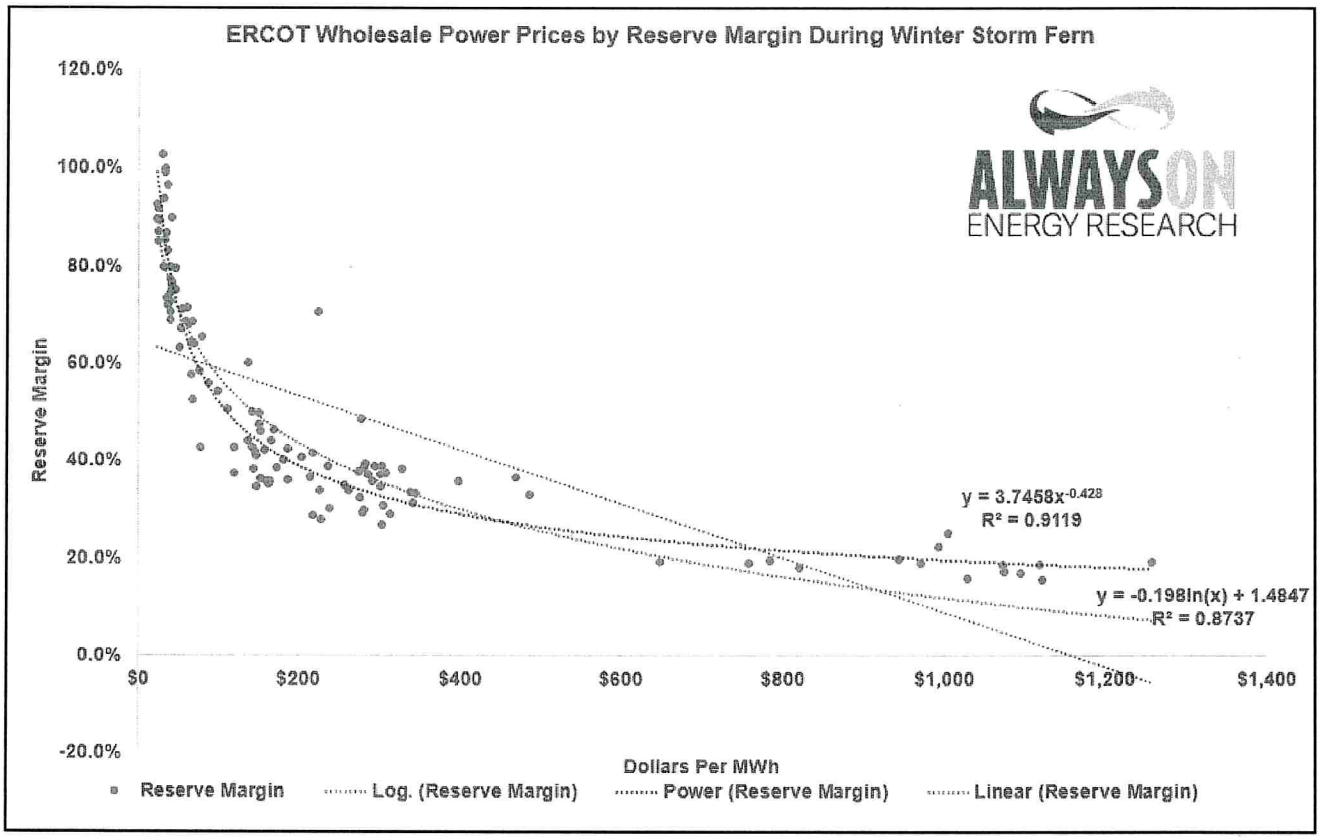
Wind, solar, and storage advocates will no doubt argue that wind and solar decrease wholesale prices when they were available, but the question isn't whether it is possi for these resources to reduce wholesale costs at times (they absolutely can).

The questions are is the grid is properly valuing reliable generators and becoming c reliant on weather based resources, and could Texas achieve greater price stability a reliability at a fraction of the cost by adding more natural gas instead of wind, solar and battery storage.

The graph below shows the wholesale electricity price in ERCOT by available reser margin. Based on the data from Winter Storm Fern, the wholesale power price skyrocketed when reserve margins dipped below approximately 26 percent.



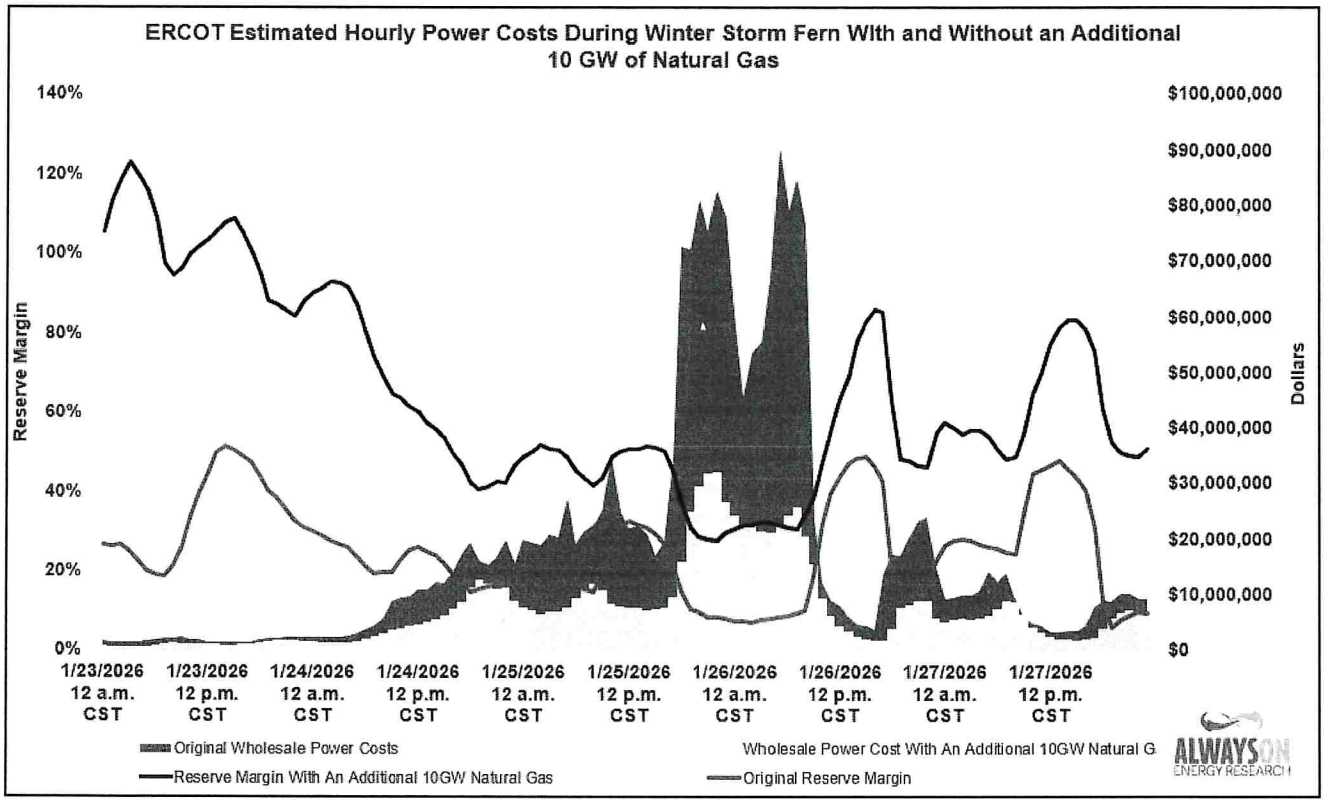
For the statisticians in the audience, this model has an R^2 of 0.91, meaning about 91 percent of the variation in ERCOT wholesale prices in this dataset is explained by changes in available reserve margin.



Because the high prices can be explained largely by the scarcity of the system, the solution is to add more dispatchable capacity that can boost the reserve margin, rat than rely on generation resources that could fall off the grid at any moment. For the last 25 years, ERCOT has been doing the latter.

We thought it would be fun to try and estimate what the hourly cost of power would based on building 10,000 MW of new natural gas capacity in ERCOT, which would probably cost $25 billion at today's prices, by matching the blended wholesale powe prices at a given reserve margin percentage in the original dataset to the MWh cost after boosting the reserve margins with new natural gas capacity.

This analysis found that the new gas capacity **could have saved Texas families and businesses $1.27 billion in power costs**, as shown in the graph below by the differe between the dark green and light green shaded areas. If any of our readers have questions, comments, or scathing rebuttals of the methodology, we look forward to discussing them in the comments.



Why Has ERCOT Failed to Add New Thermal Plants?

While natural gas additions have mostly offset coal retirements, ERCOT hasn't add any *net* dispatchable capacity since 2003. This is largely due to the energy-only mar structure, which does not properly value the differences in reliability between generators like gas and coal plants and intermittent resources like wind and solar generators.

Furthermore, Texas does not require utilities to keep enough backup capacity onlin to make sure there are always enough reliable power plants available to meet electricity demand when the wind isn't blowing or the sun isn't shining. In fact, the market structure in Texas specifically incentivizes reliable generators to **exit the market.**

As we wrote in November of 2023:

This isn't a bug of the ERCOT market; it is a feature. In a 2018 article in PVMagazine detailing a report by the WindSolar Alliance of Texas, the article author bragged about the

parasitic effect [wind and solar] electricity generators have on the revenues of more reliable power plants:

> *This is just the beginning. Texas continues to add more wind every year, and ERCOT ha estimated that the state could put online 13 GW of solar by 2030.* ***This will ultimately m more hours where coal and gas plants are not operating, and more retirements of conventional generation. [emphasis added]***

In the case of ERCOT, the parasitic impact of wind, solar, and now battery storage has not to retirements, but it has dissuaded new thermal generators from entering the market at a ti when power demand is soaring due to population growth, industrial growth, and data cente

[emphasis added]

Something's gotta give.

Conclusion

The American Clean Power Association is full of hot air.

Rather than saving Texans $200 million during Winter Storm Fern, these energy sources skipped town when the chips were down, increasing wholesale power price by $766 million compared to prices that occurred prior to their exit from the scene.

In contrast, if ERCOT had an additional 10,000 MW of gas on its system, Texans co have saved $1.27 billion in avoided scarcity prices.

Better luck next time, ACPA.