December 10, 2024

Summary

Power Vision Workshop Series I
Challenges in Meeting Surging U.S. Power Demand

The workshop (July 2024) began by highlighting concerning potential reliability issues of the nation's largest regional transmission organization (RTO), the Midcontinent Independent System Operator (MISO), as regulatory rules and power operator financial rules have accelerated a shift away from thermal energy to solar and wind.

MISO is especially dependent on coal for its power generation, putting it at unique risk of blackouts as these plants are retired. At present and under ideal conditions, coal and natural gas each account for 40% of the fuels mix, with imports, nuclear, solar, wind, and other accounting for around 20%. (Nuclear generation is declining, posing another problem for MISO.)

However, it is extremely important to distinguish installed capacity from accredited capacity. Because wind and solar are less reliably dispatchable than thermal energy sources, during periods of emergency demand there is a lower expected contribution to power generation.

The reliance on these sources of power is expected to grow substantially within MISO for three reasons:

- State mandates reducing fossil energy in favor of renewables
- Utility companies taking advantage of government subsidies to retire older depreciated generation assets and replace them with new renewable fuel sources
- Incoming EPA rules on carbon capture and storage technology, which will likely remain uneconomical enough to force coal plants to close or operate at much reduced capacity.

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Because of MISO's dependence on coal, it is one of the highest at-risk regions in the country for blackouts. At present, all areas are dependent on "just in time" deliveries of natural gas.

With many thermal plants slated to be replaced by wind and solar, there will be significantly less grid-wide reliable capacity than required capacity, causing increased risks of blackouts. By 2030, it was projected that this gap will total 14 GW. For context, this is equivalent to the entire state of Minnesota being blacked out. This analysis is based on past grid demand growth and does not include the possibility that as new data centers and high load facilities are installed they could potentially add an additional 14 GW to that gap by 2030.

Analysis of EPA's incoming rules and modeling found that capacity shortfalls would account for 19% of the total peak demand in MISO.

There are additional questions if the thermal energy plants planned to be on the grid will be hampered by EPA climate rules and local pushback, and so this may be an underestimate. For instance, there are some provisions that limited coal plants can operate at peak capacity in an emergency but there is some doubt if this would apply in practice.

It is also important to note that in the U.S., when a coal plant is shut down it is dismantled rather than mothballed. This would make it much harder to reverse course if blackouts become prevalent.

The workshop then shifted to focus on issues concerning the Electric Reliability Council of Texas (ERCOT), which administers 90% of the electricity to the state. Apart from a few local communities choosing to opt out, ERCOT is an open and restructured electricity market, with generation not vertically integrated with utilities.

Texas has been experiencing large population and economic growth in recent years, placing increased demand on the grid that is only expected to grow. This load growth is particularly concerning during periods of stress caused by severe weather events, as can be seen in the 2021 blackouts. While Texas has a reputation for heat, it is the winter months that pose the most threat, as cold weather creates issues with transmission of electricity over distances.

ERCOT has seen some of country's large increases in wind and solar capacity recently, the former of which is concentrated in north Texas, making it especially vulnerable as the first to be affected by weather events from the plains. Issues with renewable energy can quickly snowball, as oil and gas generation are being electrified for purposes of emissions reduction which has the potential to create a positive feedback loop of energy deficits for sustained power outages.

Three major issues facing ERCOT in the immediate future were identified:

- Significant reliability concerns, for which wind and solar are sizeable contributing factors during periods of no wind or sunshine;
- Gas generation is down, due both to the failure to build new and the retirement of legacy infrastructure. After the 2021 blackouts there was increased pressure to stop some retirements and add more diesel for backup generation;
- Lack of honesty about the cost of wind and solar, which due to profound technological differences are difficult to compare on the same footing. This is especially true when considering the costs that are left out in the levelized cost of electricity metric. As ERCOT does not have a capacity market, private businesses are permitted to build large quantities of wind or solar without proposing any backup capacity or considering the larger effect on the grid, and are thus able to manipulate the cost figures.

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The question of how to resolve these issues going forward is a topic of increasing concern. While recent Hurricane Beryl caused outages for several days for millions of Texans, things could have been far worse which may prompt some changes in the near future.

A bill before the Texas legislature strongly endorsed by some participants at the workshop requiring wind to contract for reserve generation when proposing new projects had been defeated in the past, however, in the wake of the above it seems likely that this will be brought back up. Additionally, state regulators are reviewing their mistakes and will likely be held accountable by consumers, effecting a change in policy. Studies are currently being conducted about the costs and benefits of burying some of the power lines to prevent further transmission problems in the future.

Finally, an additional stressor is that past estimates put the maximum percentage of electric vehicles in the fleet ERCOT could handle at 20%; recent numbers suggest this may be lower at 10-15%.

Further discussion investigated the reasons that California's electricity prices are comparatively high versus the rest of the nation. The analytical focus was on the California Independent System Operator (CAISO) region and the Pacific Gas and Electric Company (PG&E) which covers most of the state.

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The August 2020 blackouts, immediately following a notably large deficit between load and generation had developed, provided a jumping off point for this discussion. Unlike the other regions discussed during this workshop, total electricity demand was lower in 2020 and holding steady compared to previous years. Instead of excessive demand, the problem was lower generation and transmission capacity; PG&E had taken offline large portions of its transmission infrastructure in an effort to prevent fatal wildfires it had been found liable for causing in prior years.

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Three major California legislative factors were identified as driving power prices higher:

- Supply chain deregulation, especially the Public Utility Rights Policy Act of 1978 and FERC rules 888 and 889;
- California legislative programs to increase renewables, beginning with the Renewable Portfolio Standard's introduction in 2002 and then its tightening in 2015 and 2017, requiring that that the renewable portion of electricity generation grow from 20% in 2010 to 60% in 2030 and 100% by 2045;
- General California legislation targeting greenhouse gas emissions, notably in 2006 and 2007 limiting the number of coal plants and committing California to 1990 emissions levels by 2030.

These policies have resulted in the deployment of virtually all new capacity from intermittent renewable energy. Batteries have so far not provided an effective backup for intermittent power. This has resulted in strong "duck curves", which requires thermal generation to ramp up rapidly when solar drops off at nightfall. This presents degradation risks to the thermal plants if the ramp is severe. The new battery storage is helping somewhat to address those risks.

The increase in renewables (driven in part by $47.4 billion in federal subsidies, almost all of them to solar) has a notable effect on the pricing of electricity in California, as most grid size solar capacity installations are priced in long-term 20-year contracts where utilities have limited flexibility. The result is a high kWh cost.

The example of the Port of LA's recent struggles with electrification of its equipment highlights the challenges of maintaining reliability and resiliency. These categories, in addition to and beyond just affordability, are critical to consider (the strongest instance of which is blackouts).

There was a discussion of the uneven impact of high electricity on the people of California, with certain areas with harsher microclimates experiencing much more financial burden than others. Conversation had previously covered that California Public Utilities Commission was at least ostensibly concerned about this in the 2021 and 2022 "Affordability Refresh".

Commentary clarified that the port of LA's issues are outdated infrastructure problems and not a generation proble so they would not affect nor are affected by the grid situation. The rate issue in California was then brought up.

A commentator suggested that is perhaps unfair to take PG&E solar costs in Northern California as representative of the situation in all of California, as those solar generating assets were procured in 2007 and 2008 when solar was very expensive. As a result of this procurement, PG&E has been locked in a long-term high-rate contract. The case in southern California where solar was installed a little later had much better numbers for the consumer; by at the latest 2015 and 2016 renewables had become quite cost competitive.

According this commentator, there is more cause to be suspicious of the thesis that renewables are driving the higher electricity prices: since at least 1970, California's kWh prices have always been higher than the rest of the nation, long before renewables entered the scene. The scale of this premium has remained roughly constant throughout the time, only rising significantly post 2015 and especially post 2019, as driven by two factors:

- Expensive wildfire fighting and prevention programs, implemented by utilities after California instituted a law assigning 100% liability to a utility company if their equipment was shown to cause a fire, even if there was no wrongdoing. Lots of capital have gone into programs to reduce the probability and damage of a fire.
- A quarter of PG&E customers now have rooftop solar panels. In addition to a smaller electricity market while having to maintain the same infrastructure, initially PG&E was required to buy excess electricity produced by these solar panels at retail rates, an exorbitant cost. This latter problem has recently been changed so rooftop producers are compensated at the (lesser) amount of value to PG&E at the time of production, but the general issue remains.

Some suggested that independent structural issues are main culprit; most notably that the lower per capita electricity use means a greater proportion of the utilities expenses are based upon fixed rather than operational costs, which is reflected in the final rates.

An intriguing area for further research would be a comparison of the comparably high renewable growth in Texas and California which have antipodal electricity regulatory philosophy, California being extremely command and control and Texas being strongly free market.

The workshop ended with commentary predicting significant blackouts in the United States, not just by 2050 but within the next 5-10 years. The presentation did a deep dive for the RTO in charge of the mid-Atlantic region, PJM, and extrapolated to national conclusions.

At present, PJM is made up of around 200 GW of system capacity, with peak load at around 150 GW and almost all generation from dispatchable sources. The critical factor driving the risk of blackouts is the disorderly retirement of these legacy thermal energy plants, especially coal. The presenter on this topic conducted an analysis by gathering data from every thermal plant in PJM and projecting retirement based on three major contribution factors:

- Current environmental regulations and subsidies make certain thermal energy plants harder to operate profitably and compete with incentives for new renewable capacity;

- Existing thermal plants wear out due to aging, exacerbated by the aggressive ramping that has been used to accommodate the renewable duck curve;
- EPA regulations, especially two EPA rules coming into force in 2028 that restrict coal ash ponds and wastewater effluents are very difficult to meet profitably.

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Based upon these rules, 13 GW of coal plants are projected to retire just in 2028, for a total of 31 GW in thermal retirements by 2030. This is consistent with PJM's optimistic scenario that attempts to make up of the loss of this capacity with 47 GW of nameplate solar and wind capacity each, and around 4 GW of natural gas and battery capacity each. Including this year's revised numbers for load growth due likely to data centers (PJM has some of the largest concentrations of data centers in the U.S.) and EV charging, projections were made for the likely load and capacity in every hour of 2030.

The largest stressors come in the summer where heat causes wind turbines to operate significantly less effectively and after dark when there is no longer enough sunshine to provide ample solar energy. During its worst hour, at 5pm on September 5, 2030, PJM demand exceeds generating capacity by 10%. In total, throughout the year 2030, there are 10 days with blackouts for a total of 41 hours.

This isn't just a PJM but a national issue. The Southwest Power Pool is projected to fare twice as bad; MISO to fair better but still experience some blackouts. Blackouts cause significant negative social disruptions that must be avoided to prevent cascading sociopolitical problems.

The situation is so severe, even in PJM's optimistic scenario that no single policy change can be made guaranteeing a fix. The question is when will policy makers start acting to mitigate the effects, but if they wait until blackouts, it may be too late.

One problem obscuring this issue for policy makers is the North American Electric Reliability Corporation (NERC)'s failure to model future thermal plant closures. In PJM thermal plants only need to give three months' notice for retirement; having not received notice NERC assumes these plants will be operating at full capacity through 2030 and concludes PJM is only at "normal risk for blackouts", quantitively calculated to zero probability to three significant figures through at least 2026. This dangerously understates the serious risk around the corner.

Following the presentations, a roundtable discussion was held. Multiple participants reflected that current policies had been driven by ideological thinking and were not based in the factual importance of infrastructure and transmission reliability. Lacking political will and a simple fix to this enormous challenge, most participants believed that the only path for change was after the blackouts had started and deemed unacceptable by the American public. The conflict between political legislative mandates and the technical operation of grid administrators was proposed as contributing factor, whereas anoter participant indicted the whole system, stating that if the problem had reached this scale, there had to be a failure on every level of the government and regulatory structure.

There was some pushback on the scale of this latter condemnation, with a participant familiar with the regulatory habitus stating that 95% of regulators were good people balancing complicated concerns, sometimes with incomplete or bad information. The participants found broad agreement that subsidies needed to be scaled back to not enter a "death spiral", though it was noted that some thermal energy sources also receive sizeable subsidies that had not been discussed. The hope of removing subsidies was that rather than investments being driven in a command-and-control manner to force certain results in various localities, the energy economy could act in a more unified manner—solar placed optimally for their generation capacity and natural gas infrastructure aligned most efficiently for its advantages.

Finally, there was an interesting paradoxical agreement that the places to look in the U.S. for important lessons are California and Texas, which through almost opposite regulatory system have become the most renewable-dependent grids. They had to meet reality sooner than abstract projections, and the detail of California's modelling grew more sophisticated as they modified their objectives to be more achievable. The important challenges the rest of the country will soon face are already evident in California and Texas.

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