Addressing Resilience of Texas Electrical Grid and Beyond - Executive Perspective

Moderators: Damir Novosel, President, Quanta Technology, and John McDonald, Smart Grid Business Development Leader, GE Grid Solutions

- Mark Carpenter, SVP, ONCOR
- Mark Lauby, SVP, NERC
- Tom Pierpoint, VP, Austin Energy
- Doug Howe, Board of Directors at New Mexico Renewable Energy Transmission Authority

Follow-up message:

We would like to sincerely thank everyone that works so hard to improve our industry. The Energy Utility industry is unlike many other industries fostering the open collaboration, information exchange, and the willingness to assist each other in emergencies.

Professional associations, such as Cigre, allow all of us to work together and contribute our diverse skills and perspectives on common industry problems. Cigre members are from utilities, government, national labs, consulting, vendors, suppliers, academia, and many other areas and panels like this provide unique perspective for open and objective discussions.

We appreciate the many questions and comments that were provided during and after the session. These are attached and provide a good opportunity for reflection. A hopeful outcome of this session is that information that was conveyed can be used by you to shape your part of this vital Industry.

Below are responses to additional questions that panelists did not answer due to time constraints. Other questions have been answered verbally during the session.

Additional Questions & Answers

Mark Carpenter, SVP, ONCOR

1. Do you believe a third-party analysis of ERCOT grid stability would be beneficial to prevent events such as these in the future? (Enjoying this talk) - Mirka Mandich, mirka@ieee.org

   From my perspective, there were no grid stability issues related to the event. There simply wasn't enough generation to meet the demand. The load shed that was implemented recovered the system frequency. Reference the two preliminary ERCOT reports in the links below:

   - *http://www.ercot.com/content/wcm/key_documents_lists/225373/2.2_REVISED_ERCOT_Presentation.pdf* ,
   - *http://www.ercot.com/content/wcm/lists/226521/51878_ERCOT_Letter_re_Preliminary_Report_on_Outage_Causes.pdf*)

They show that the expected peak load was 76,819 MW and the available generation was 56,341 MW. The reports also shows that weather, equipment problems, and fuel supply were the primary factors in around unit availability. The gap between the 59.3 Hz relay setting for the Stage 1 of the underfrequency relay scheme and the 59.4 Hz nine-minute ride-through that is expected of the generators is being reviewed. This entire event is getting significant review by a number of parties. The comprehensive NERC review will be the foundation for future reviews and action plans. The NERC report should be out later this year.

2. How close were you to an underfrequency load shed? - David Roop, droop9495@gmail.com

   The first ERCOT presentation listed above show that 59.302 was the lowest frequency recorded. The first stage of the underfrequency relay scheme is set to trip at 59.3 Hz. In Oncor's case, 12 distribution feeders (69 MW of load) tripped due to operations of the underfrequency relays and were quickly restored to rearm the scheme after other feeders were removed from service. These operations were within the tolerance specifications of the relays. This is only 4% of the Stage 1 relays or less than 1% of the relays associated with the underfrequency relaying scheme.

3. What positive experience can you share about keeping the system from blackout. What improvement can be made in the area of load shedding to make it work better if this would happen again? - Yilu liu, liu@utk.edu

   ERCOT and the associated transmission/distribution companies' load shed plans, training, and drills are solid. However, I do not think anyone conceived of having to shed 20,000 MW of load. While this was a horrible societal event, we were able to successfully scale-up the load shed and avoid a black start situation. Had we gone to black start, the societal impact would have been significantly greater.

   At Oncor, 40% (25% of the load) of the feeders are on underfrequency relays, 9% of the feeders are exempt from load shed (hospitals, known gas supplies to generation station, major airports, downtown networks, and 911 centers), and 51% are associated with the load shed plans. Plans call for 30 minute "off periods" followed by much longer "on periods". Because of the amount load that was shed, the "off periods" were significantly longer than the "on periods".

   Several learning from the event, especially if it were to be as deep and as long as the February event, include:

   - Some critical facilities such as water pumping stations can tolerate short "off periods" followed by long "on periods" but they cannot tolerate extended outages. Accommodations will need to be made for these situations. Keep in mind that such facilities are often on one-way feeds that are subjected to outages for events on the distribution system.
   - If the size of the system is reduced due to load shed, it makes sense that some of the feeders in the underfrequency (UF) load -shed system could be moved to the rotational outage group for two reasons:
     - If a large amount of load is intentionally removed from the system, the UF feeders will make up much more than 25% of the connected load and their sudden operation could actually cause over-speed issues.

    - Their inclusion will improve the rotational experience for other customers by spreading the load shed among more feeders to improve the ratio of "off time" to "on time".
- Because of cold load pickup issues, overall distribution system design, equipment, and fuse sizing is being reviewed.
- Utilization of distribution automation may facilitate a slightly more surgical approach to load shed in some cases.
- Customer perception of unfairness needs to be addressed since some were out-aged for long periods while others had no outages (UF or exempted feeders).
- Customer and regulatory communications need improvements.

4. Can the large amount of rooftop solar plants can simplify the rotating load shedding schemes easier to be effective during cascading outages in transmission network? - Priyatosh Mahish, priyatosh.mahish@iemcal.com

   I do not think rooftop solar would simplify the load rotating schemes. There were no cascading outages of the transmission system. There was simply insufficient generation available to meet the load demand. In this particular case, rooftop solar would have only been of benefit to off-set some daytime load. Generally, between the ice and the clouds, the solar performance did not appear to be very impactful.

5. I have two questions: 1. Looking at the operation data, at 1:23 am, ERCOT grid frequency was closely to 59.9 Hz and 1000 MW load-shed was ordered due to some issues. How much was spinning or hot reserve during that time when load-shed ordered. 2. What about WECC, SPP & SERC interconnections option, when frequency falls below 59.5 Hz? - Tapan Manna, tmanna@burnsmcd.com

   Concerning question 1 - I think the NERC report will more completely answer this question when it is completed. From the perspective of the transmission control room, ERCOT will direct load shed when the Physical Responsive Reserve falls below 1000 MW and is not projected to recover in 30 minutes or when the clock-minute frequency falls below 59.91 Hz for 30 consecutive minutes.

   Concerning question 2 - There are no synchronous ties to other grids. There are several DC ties that are used to import power.

6. Was extreme load actually the issue, I was thinking the loads were comparable to summer air conditioning loads (is that correct?). Really, don't we primary need to address generation winter proofing the wind turbines and the natural gas pipeline and any other winter-based failures? T&D may have some smaller issues, but the real issues is generation (I think). when you lose that much load T&D can barely respond. Can someone speak more to gen. winter root causes? how easily can that be fixed? - Rod Ratcliff, rod.ratcliff@powereng.com

   Traditionally ERCOT has been a summer peaking system. The all-time summer peak was in August 2019 at 74,820 MW. Before this event, the winter peak had been 65,915 MW set in January 2018. On the Sunday evening February 14, hours before the load shed event occurred, a new system winter peak was set at 69,222 MW. Because temperatures were continuing to *decline Monday and Tuesday, had generation been available, the expected peak was 76,819 MW. Although natural gas is a major source of heating energy in Texas, unlike northern states, electric resistive heat and heat pumps have dominate use. At very cold temperatures, heat pumps auxiliary resistive heat strips engage and add significant load to the system. Generation issues and fuel supply were the most significant factors in this event. The links referenced in question 2 will show that; however, due to extreme load, even if the generation that was on-line on Sunday February 14 had performed much better, there was a reasonable probability that some load shed would have been necessary to get past the morning and evening peaks. This would have taken the form of controllable rotating outages that would have had much less customer impact. The final NERC report and other ongoing studies should identify the root cause of the generation and fuel issues.*

Mark Lauby, SVP, NERC

1. Is NERC developing some type of resilience standards? How to define the relationship between reliability and resilience? Can resilience be put under reliability umbrella together with adequacy and security? Can you recommend the most appropriate resilience metrics that utility industry should be using? - Milorad Papic, mi_pa2@yahoo.com

   Currently, with industry's support, a generating unit winterization Reliability Standard is approved and sent to FERC for their consideration. However, there is more to be done. The ongoing FERC/ERO Enterprise joint inquiry is expected to identify actions, which may include more than plant winterization, but also discuss emergency operation planning, key load prioritization, etc. to support higher levels of resilience with a resource mix that is more sensitive to extreme cold/heat as well as moisture/solar/wind droughts. In the meantime, working with industry to address the gaps between now and the development of new Reliability Standards/enhancement to existing Standards, we will employ ERO Policies, Procedures, and Programs to increase the readiness of the Balancing Authorities, Transmission Operators and Reliability Coordinators to be resilient during extreme temperature and winter weather conditions.

   A view on resilience is incorporated in NERC's Report on Resilience. In most cases resilience models use the United States National Infrastructure Advisory Council (NIAC) Framework for establishing Critical Infrastructure Goals, though refined further to focus specifically on the bulk power system characteristics. Information about this report can be found at ➔ https://www.trccompanies.com/insights/nerc-issues-2018-resilience-report/

   NERC has proposed a number of metrics:

   1. ***Robustness:*** *the measured ability to withstand certain threats*
   2. ***Amplitude:*** *a measure of the impact on BPS performance*
   3. ***Degradation:*** *a measure of a change in system response with respect to an impact of varying amplitude*
   4. ***Recovery:*** *a measure of the rate at which the system returns (rebounds) to a normal or stable state after the disruptive event, including any preparation time*
   5. ***Recovery state:*** *the state of BPS performance following the recovery period.*
      a. *Stable*
      b. *Improved*

c. Deteriorated

Further, there is a need to development of additional metrics that measure impacts from emerging risks (e.g., energy sufficiency and transmission/generation operating technology security). These metrics can inform industry on the extent of the condition, level of risk, and relative success of their mitigation.

2. Indeed, resource mix is important. Would it be inevitable that there will be over-build because some renewable capacity will not produce, e.g., after sunset? - Henry Chao, hchao@quanta-technology.com

   Remembering that Capacity = Energy + Essential Reliability Service + Flexibility, rather than working solely from the capacity as industry has done traditionally, the requirements for each of these components need to be analyzed, which will then result in the needed capacity. So, this is not overbuilt, but rather, built to meet reliability and resilience objectives.

3. How can the industry—NERC and the ISOs—improve capacity responses/requirements in light of ramp-rate needs, extreme weather events, back-feeding feeders, the lack of visibility of distributed resources, etc. - Jeff Palermo, jeff@pjp-consulting.com

   See response to question 2. Industry may require new tools and "rules of thumb" towards gaining not only the visibility, but to understand the requirements to sustain r improve reliability and resilience of the future bulk power system, where capacity, essential reliability services and flexibility will drive resource requirements.

4. Why does it make sense to allow so much wind generation operate day to day, but have the ERCOT seasonal planning not credit that generation? It seems like the is a disconnect between system operations (allowing generation not capable of operating during cold weather) and system planning. Is the wind generation getting a ""free"" pass? - Robert Carritte, rcarritte@mpr.com

   We await the result of the ongoing FERC/ERO Enterprise joint inquiry to identify actions to address challenges such as integration of variable energy resources, gas-electric dependency, emergency operations planning, and the need to improve resilience.

5. Why ERCOT keep running in to resource adequacy issues even with pre-planned power plant outages after February winter storm? Do you see a fundamental gap in the planning practices? - Amir Kazemi, reza.kazemi@ge.com

   The challenge is beyond ERCOT, but rather a characteristic of the transformed resource mix that we must address in planning, operational planning, and operational timeframes. See answer to question 2 on potential next steps.

6. ERCOT is on a 'reduce power' advisory. Does this mean we will be balancing on the knifes edge throughout the summer? What can be done in short term to address this resource adequacy challenge (from now to end of this year)? - Hasala Dharmawardena, hasala@ieee.org

This as a broader question than just ERCOT. Namely as mentioned in question 5, this is a characteristic of the transformed resource mix that we must address in planning, operational planning, and operational timeframes. See answer to question 2 on potential next steps.

Tom Pierpoint, VP, Austin Energy

I have worked at a number of Utilities. The following responses draw from this broader experience as well as engagement in industry and professional groups such as Cigre. These responses are not intended to be definitive answers but instead hopefully provide thought provoking information. It is important for members of industry professional associations, such as Cigre, to continue to participate in various industry forums and advocate possible solutions to these many complex problems.

1. How to define the relationship between reliability and resilience? Can resilience be put under reliability umbrella together with adequacy and security? Can you recommend the most appropriate resilience metrics that utility industry should be using? – Milorad Papic, mi_pa2@yahoo.com

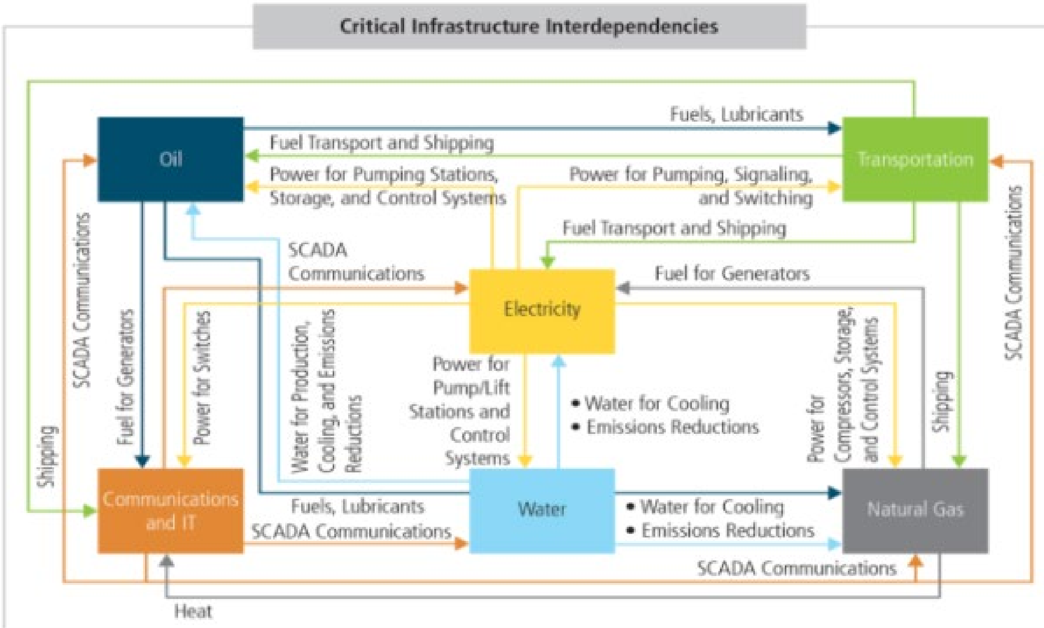
   This is a very collaborative industry. Many members of Cigre are also part of IEEE. Collaborative and important initiatives to mention are on "The Definition and Quantification of Resilience" and "Resilience Framework, Methods, and Metrics for Electricity Sector" developed under the IEEE PES Industry Technical Support Leadership Committee. Those useful documents can be found at ➔ https://grouper.ieee.org/groups/transformers/subcommittees/distr/C57.167/F18-Definition&QuantificationOfResilience.pdf

   ➔ https://resourcecenter.ieee-pes.org/publications/technical-reports/PES_TP_TR83_ITSLC_102920.html

   This IEEE Team is defining Metrics that can be used by participants in our industry to measure Resilience. The IEEE Resilience Metrics are envisioned to be similar in approach to the IEEE Reliability Metrics, which have largely been adopted in the Utility Industry. We know that the IEEE PES team appreciates your interest, support, and awareness in this effort.

2. Any thoughts how to study the prevention of the resilience event which impact multiple infrastructures (electric, gas, water, communication etc.)? – Milorad Papic, mi_pa2@yahoo.com

   The inter-related infrastructures have been identified, documented, and discussed at length. This includes the White House / Department of Energy Quadrennial Energy Review which was initiated in 2014 with publication installments in 2015 through 2017. The following diagram has been published in numerous documents including the QER. This diagram and further information can be found at ➔ https://www.emergingenergyinsights.com/2017/01/transforming-nations-electricity-system-four-part-examination-quadrennial-energy-review/



It is important for industry professional associations to continue to participate in various industry forums and advocate possible solutions to this complex problem.

Prevention of resilience events must focus on the Planning (1-5 years), Operational Planning (1 day to 1 year) and Operational (day of) time frames. Planning to include developing a resource mix that meets desired resilience levels. Operational Planning to ensure that all elements available to manage resilience events are understood and ready to support. Operations that iniate the pans to mnage resilience events. Each of these time frames need to be assessed n light of the transformed resource mix to ensure evens are managed and desired resilience levels achieved.

3. For Texas, load spike during the cold spell made the situation a lot worse. Any suggestion how this should be managed? - Yi Hu, yhu@quanta-technology.com

   One area that is being explored for further expansion is Demand Response. This is a proven technique to reduce load spikes. These programs can be administered either at the wholesale level (i.e., an ERCOT type of entity) or at a retail level (a Utility). A good description of these types of programs and their current penetration levels starts on page 14 of "BUILDING AN INTELLIGENT ELECTRIC GRID FOR THE 21ST CENTURY." This document can be found at ➔ https://ieeeusa.org/wp-content/uploads/2021/02/IEEEUSAWP-BuildinganIntelligentGrid2020.pdf

   Study of events that are outside of the traditional load forecasting methods can provide book-ended views of the potential impacts and mitigation approaches. One needs to go beyond probable (such as 90/10 load forecasts) to plausible, especially for winter events where more experience is needed to manage impacts.

4. Where do you think demand side flexibility should play to address resiliency issues? - Hasala Dharmawardena, hasala@ieee.org

   Many electric feeders can be cycled on and off during Load Shed events, whether in Texas or elsewhere in the U.S. However, the nature of equipment in large commercial and industrial facilities results in great disruption from cycling. On the other hand, these facilities can often greatly reduce and even go into "idling" of most load.

   As such, Demand side management is absolutely critical during Load Shed events especially for applicable large commercial and industrial customers. We can expect to see a great deal of work in this area across the U.S. following the Texas storms.

5. Texas is becoming a large market for battery energy storage systems (BESS) co-located with wind/solar. Given the operating temperature constraints of BESS, is there any data as to the deployment of the on-line BESS (i.e., percent of available BESS that were actually used)? - Greg Magsaysay, gregmags@icloud.com

   The After-Action Findings are still being compiled by various entities across Texas. There is not currently definitive data on BESS at this point.

Doug Howe, Board of Directors at New Mexico Renewable Energy Transmission Authority

1. So, based on recent temperature extremes, improving resiliency means weatherizing generation. But then in future if extreme weather manifests as heavy rain (like Sandy storm). So, what design criteria do we use to build our infrastructure? - Mahendra Patel, mpatel@epri.com

   I interpret your question as essentially asking: if climate is changing in unpredictable ways, how do we plan for resource adequacy in the future especially given that generation resources tend to be long-lived, capital intensive assets? It is a good question and there probably is not a definitive, scientific answer to it unfortunately. So, it is going to rely on the judgement of generation owners and their regulators to plan based on what they know today and what climate science is telling them is probable about the future. The February 2021 event was a repeat of the February 2011 event, though 2011 event was probably somewhat more extreme in west Texas and New Mexico than in the ERCOT portion of Texas. In 2011, natural gas supplies were cut off to a large part of West Texas and NM, causing hundreds of millions in damage. The result: those utilities were instructed by their regulators to harden their natural gas and electricity facilities. That did not happen in ERCOT following the 2011 event, so the 2021 event was not nearly as traumatic in West Texas and NM as it was in ERCOT. It is useful to note that the 2021 event in ERCOT was a 1-in-10 event so was arguably within the planning criteria. The problem is that the 1-in-10 criterion, by itself, does not take into account severity of the event. 1-in-10 might be the right criterion of a low-probability event, but impact of the event has to be added to the analysis.

   Further, operational planning and operational approaches may need revisiting so that extreme temperature events are part of overall emergency plans, beyond traditional "extreme" events.

2. In the short term, would a framework to pay consumers to reduce electricity usage or provide other incentives to aid in reducing demand help? What lessons can other grid operators learn from it? - Sid Ashok, sidharth.ashok@nationalgrid.com

Yes, is the short answer. CAISO is taking a very serious look at revamping its whole approach to demand response, especially as a tool to deploy prior to controlled rotating outages during system emergencies. In organized markets, like CAISO and ERCOT, one of the problems is that demand response has been treated as equivalent to generation and therefore subject to the same bidding rules. Experience has shown us that has not been terribly effective, because surveys have shown that electricity consumers value the loss of electricity (termed Value of Lost Load, or VOLL) much higher than bid prices for generation resources, even in times of system stress. They key to deploying demand response is that market operators have to be able to offer much higher (and I mean much, much higher) prices for load curtailment in system stress periods when there is not enough supply to meet demand. Suppose you could, for example, offer $25,000 per MWh for curtailment. That sounds like a lot, but if that curtailment is spread around so that no customer is out more than a few hours per day, I've seen analyses show that it could cost a lot less to do that than the sort of damage and misery caused by putting customers out for several consecutive days.

That said, consumers would need to know what are the potential impacts and mitigations they should consider. For example, if extreme cold is expected for days, what back-up systems should the consumer consider towards participating in interruption programs?

3. Can the panelist please comment on the increasing "electrification" of the USA including, at least in Texas the high growth in use of electric heat in homes?

   ERCOT recently said the February weather event was a 1 in a 100-year event? Do the panelists agree with that? And as was stated do the panelists believe that the cost for designing for an event that infrequent would be tolerated by ratepayers? – Wesley Oliphant, woliphant@exoinc.com

   I certainly do not see this as a 1-in-100-year event since a similar winter event occurred in 2011. As per my answer above, whether customers will tolerate that expense depends on the impact that the event has had on them and their lives. Consumers are either going to pay for resource resiliency investments, or they will pay to clean up the damage caused by inadequate preparation. I am not saying that no cost should be spared in preparing for climate resiliency, but I am saying that climate change is likely to cost big, big money whether we wait until the damage occurs or try to prepare and prevent the damage. It is going to take some careful analysis and judgement to determine the "goldilocks" zone or proactive spending versus reactive spending.

4. Connecting ERCOT with Eastern and Western Interconnections by AC may give rise to widespread blackouts. HVDC interconnections may provide needed energy during extreme events but limit widespread outages. - Rambabu Adapa, radapa@epri.com

   There have been studies done, for example, of connecting the eastern and western interconnections via AC. I am told it can be done but doing so raises a lot of technical issues that would have to be solved first. The bottom line was that the cost and benefits of AC interconnection of the E and W grids just could not pencil out. I suspect the same would likely be true with connecting ERCOT to either the eastern or western interconnect via AC: benefits will not supersede costs. In addition, an AC interconnection to either the E or W grid would certainly bring ERCOT under the full jurisdiction of the FERC, which has been historically a political red-line.

Building more and larger DC interties might be more cost-effective, but that has also run into political resistance in the past. We have to remember that there was a proposal called the "Tres Amigos Super-Station" that was to be three-way DC interconnection with eastern, western and ERCOT grids that would be capable of about 2000-3000 MW transfer in any direction. Although the project was approved by the eastern and western grid balancing area authorities to which it would interconnect, the proposal died when the PUCT would not approve it because of political resistance to the prospect that such an interconnection might extend FERC regulation into ERCOT. I suspect any proposal for a new DC interconnection to ERCOT might run into similar problems, unless the PUCT has changed its views about the possibility of FERC regulation. However, even if it had received PUCT approval, there was always a question of whether the Tres Amigos project was commercially feasible.

One of many sources that might provide further technical insights is the NREL Seams effort. This includes high level overviews as well as detailed information on this complex issue. Studies have primarily focused on tying the Eastern and Western Grid, including Canada. Further studies also including the Texas ERCOT region and Mexico (diagram below is from the NREL SEAMS site).