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CONTENTS

1 President's Message

4 The Texas Freeze Out: Electric Power Systems, Markets and the Future

8 Highlights of IAEE 2021 Online Conference's Main Sessions

12 Climate and Power System Reliability in the Aftermath of the Texas Blackouts

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

20 The Texas Power Crisis Seen from the EU: a testbed for its resilience and risk-preparedness rules

23 Texas Power Outages Revealed Supply Vulnerabilities[1]

26 Vulnerabilities in the Texas Electricity Market: A Comparison of Winter Events in 2021 and 1989

29 The Catastrophic Texas Blackouts: Lessons For The Developing Countries

31 Vulnerability in the utility industry: perspective, experiences and lessons from the European Union[1]

35 What is the Value of Security of Supply for Households and Business Consumers? An Assessment Accounting for Trade-offs and Psychological Drivers

42 Calendar

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PRESIDENT'S MESSAGE

I send my best regards to all of you, along with my sincere hope that some degree of normalcy has begun to return to your everyday lives. Although recovery and emergence from the pandemic is not proceeding at the same rate everywhere, there are some indications that the restrictions that have contained and frustrated us for so many months have begun to be lifted. Vaccines are playing a large role in that, so I encourage you to consider taking the vaccine as soon as possible, if you have not already done so. And fingers crossed that we will all be able to meet together in Tokyo next summer for IAEE's 43rd International Conference! Planning is well underway for that important event—one that will (we hope) mark a triumphant emergence from the quarantines, lock-downs, and distancing that have governed us for such a long time.

Speaking of triumphs and conferences, I am pleased to say that IAEE's recently concluded 1st International Online Conference exceeded all my expectations and was a great success! Like the blind man who was able to touch the elephant in only a few places, I may not have the complete picture in mind yet. But, based on the parts that I was able to touch (not inconsiderable), the event achieved everything that we wished for, and more. With more than 900 participants joining the online confab from 62 countries, we were finally able to meet and greet again (if only virtually). During the 16 keynote sessions we heard from many of the world's leading experts on the meaning and implications of the much vaunted energy transition. We were also able to learn from and provide feedback to hundreds of researchers whose work was presented during 137 concurrent sessions, and to assess and reward the very excellent research presented by many of IAEE's student members, and much more.

We have many people to thank for the efforts that made this event such a great success. Our deepest gratitude goes out to Yannick Perez and Jean-Michel Glachant, whose leadership, supported by the tireless efforts of their respective teams working respectively from the French Association for Energy Economics and the Florence School of Regulation, made all of this possible. From the beginning, the decision to attempt a virtual conference was rightfully viewed as a risky and difficult undertaking, something that we had never attempted before, and something necessarily completed subject to rather short and scary deadlines, not to mention all of the uncertainties imposed by Covid, etc. It is a relief, but not a surprise, to look back now and realize that everyone who took part in the planning and execution of our conference has exceeded our highest expectations,

(continued on page 2)

President's Message (continued)

succeeded in spectacular fashion, and earned the gratitude of all IAEE members, I am sure. This definitely marks a high point in the history of the IAEE. Something that will not be forgotten.

Speaking not as your President but as a simple economist who is now reflecting on the conference—including all that was said and all that we may have learned—I want to emphasize two key concepts that are central to finding solutions to the problems we now face. The first is the concept of "economic externalities." We all know what that term means and we know that externalities lay at the heart of every discussion of climate change. And, the second concept I want to mention is that of "opportunity cost," which recognizes that any choice we make is at the expense of other things we must leave behind.

Economics has been defined as the study of how limited resources are used to satisfy unlimited wants. If we were so lucky to be endowed with sufficient resources to be able to afford every good thing, life would be easy because we would not have to choose among alternatives, but then there would be little real work to keep economists employed. Unfortunately (or perhaps fortunately for economists), that is not the world in which we live. Instead, our opportunities and decisions are constrained by limited resources, and the best we can do is to choose wisely from among many good things.

In keeping with one major theme of our recent conference, let me provide an illustration drawn from the context of the global pandemic. We know that it would be good for all senior citizens and other vulnerable people to receive both doses of the vaccine as soon as possible. But, it would also be good for younger and healthy people to receive at least one dose as soon as possible. Both actions have beneficial effects, both are desirable in their own right, but we cannot have both. By committing to one, we give up the other.

My point is that we, as economists, must be careful when studying the potential beneficial impacts of any particular policy (whether it pertains to climate change, income distribution, public health, or other matters), to also identify just what that policy would require us to give up—we would take the chosen path instead of what? We have not done our job, and society cannot make sound decisions, until both parts of the analysis are complete; that is to say, until we have answered the question most fundamental to economics: "instead of what?"

James L. Smith

Careers, Energy Education and Scholarships Online Databases

IAEE is pleased to highlight our online careers database, with special focus on graduate positions. Please visit http://www.iaee.org/en/students/student_careers.asp for a listing of employment opportunities.

Employers are invited to use this database, at no cost, to advertise their graduate, senior graduate or seasoned professional positions to the IAEE membership and visitors to the IAEE website seeking employment assistance.

The IAEE is also pleased to highlight the Energy Economics Education database available at http://www.iaee.org/en/students/eee.aspx Members from academia are kindly invited to list, at no cost, graduate, postgraduate and research programs as well as their university and research centers in this online database. For students and interested individuals looking to enhance their knowledge within the field of energy and economics, this is a valuable database to reference.

Further, IAEE has also launched a Scholarship Database, open at no cost to different grants and scholarship providers in Energy Economics and related fields. This is available at http://www.iaee.org/en/students/ListScholarships.aspx.

We look forward to your participation in these new initiatives.

Editor's Notes

Response to our call for submissions on vulnerabilities within the utility industry: what has occurred, what are your concerns, and research on risk exposure and mitigation techniques has been most gratifying. We will complete this topic and shift to how Energy Transition is affecting members in their geographic locales in the next issue.

During February 7-21, 2021 an Arctic oscillation, a "polar vortex", enabled freezing air to penetrate the U.S. midcontinent into Mexico, forcing temperatures below long-standing records for durations that also set new records. The extent and duration of power outages in Texas garnered national and international attention. In this article, **Michelle Michot Foss**, **Pat Wood III**, and **Brett Perlman** add observations on what they believe they have learned as of this writing.

Nicolo Rossetto and **Jean-Michel Glachant** provide an insightful summary of the main sessions of the 1st IAEE 2021 Online Conference. This inaugural event was well attended with almost 1000 registrants and 600 speakers attending more than 150 sessions.

The February 2021 blackout in Texas underscored the importance of reliable and resilient power systems. **Marie Petitet**, **Burcin Unel**, **Rolando Fuentes**, and **Frank A. Felder** discuss the roles of regulators, markets, fuel and generation supply chains, and interdependent infrastructures, and finds that they need to be reconsidered and redefined to successfully meet the future challenges of increased electrification and severe weather.

Todd Aagaard and **Andrew Kleit** state that 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.

Anne Houtman and **Mariana Liakopoulou** write that the chain of events in the Texas crisis is a testbed for the relevance and more importantly, the effective implementation of the rules the European Union (EU) introduced in recent years on the security of its electricity and gas systems, aiming at improving their resilience and risk-preparedness.

Fereidoon Sioshansi notes that the Texas power shortages of February 2021 were caused by an extremely cold spell in a system that is customarily prepared to handle extreme hot summers but not adequately winterized. Despite attempts by some politicians to blame wind, it was mostly thermal plants that failed.

Jay Zarnikau informs us that the winter storms that hit Texas in December 1989 and February 2021 were similar in many respects, but had remarkably different impacts on the state's electricity system.

Tilak K. Doshi looks at the lessons to be learned from the catastrophic power outages resulting from severe snowstorms in Texas earlier this year. Developing countries may learn important insights from the decisions that lead to this debacle.

The European Union is taking initiatives to increase its security of supply, reduce operational vulnerabilities and respond to the threats. An article by **Francesco Careri**, **Catalin Felix Covrig**, and **Tilemahos Efthimiadis** presents examples, with a focus on the Risk Preparedness Regulation, and the Baltic synchronization plan

Alessandra Motz posits that the damage that households and businesses suffer because of a blackout may be influenced by psychological traits, and may as well reflect the perceived trade-offs between security and environmental sustainability of the electricity supply. Two analyses conducted in Switzerland provide an example on the role and impact of these drivers.

DLW

The Texas Freeze Out: Electric Power Systems, Markets and the Future

BY MICHELLE MICHOT FOSS, PAT WOOD III, AND **BRETT PERLMAN**

Michelle Michot Foss is a Fellow at the Center for Energy Studies, Rice University's Baker Institute for Public Policy. She can be reached at michelle.m.foss@rice.edu. **Pat Wood III** is the CEO of Hunt Energy Network and the former chairman PUCT and FERC. **Brett Perlman** is the CEO of the Center for Houston's Future and former member, PUCT.

Backdrop

During February 7-21, 2021 an Arctic oscillation, a "polar vortex", enabled freezing air to penetrate the U.S. midcontinent into Mexico, forcing temperatures below long-standing records for durations that also set new records.[1]

The extent and duration of power outages in Texas garnered national and international attention. In this article, we add observations on what we believe we have learned as of this writing.

Tracking the Event

As early as November 5, 2020, meteorological warnings were issued by the Electric Reliability Council of Texas, ERCOT, which oversees most of the state's grid, to all market participants warning of the possibility for an extreme cold event during winter 2020-2021. During late fall 2020, weather forecast services began to include discussion of shifting conditions.[2] On February 3, 2021, ERCOT warned market participants of the coldest weather of the year (Figure 2). These warnings tracked news and alerts from commercial weather outlets. As the timeline progressed, ERCOT issued an Operating Condition Notice, OCN, an advisory, and a watch. During an ERCOT Board meeting on February 9, 2021, ERCOT's CEO warned the Board that ERCOT "might have a little bit of winter weather to contend with."[3]

A Texas Energy Reliability Council (TERC) meeting was held on February 12. TERC brings together the two regulatory bodies within Texas – the Railroad Commission, RRC, which oversees the states natural gas industry and the Public Utility Commission of Texas, PUCT, which oversees electric power. Through TERC, the RRC and PUCT coordinate with ERCOT and the natural gas industry to manage curtailments. The RRC curtailment plan gives "highest priority for gas availability and delivery on residences, hospital, schools, churches and other human needs customers".[4] By emergency order that day, the RRC took steps to update its 1973 curtailment plan to prioritize "deliveries of gas to electric generation facilities which serve human needs customers," a step it had been first advised to take in 2003.[5]

Communications and interactions across the key agencies and gas and electric industries intensified as weather conditions worsened (Figure 2). These culminated in an appeal for conservation measures on February 14.

The shock to the energy system unfolded as shown in Figure 3. By noon on February 15, ERCOT had crossed all three levels of emergency operations, invoking an Emergency Energy Alert (EEA) 3 early on February 15 and directing transmission operators to curtail 10,000 MW of firm load.[6]

In the Figure 4 panels, we show electricity generation by source for the month of February 2021 and since 2014. These compare with outage data from ERCOT in Figure 5.[7] In the spring weather prior to onset of the freeze, wind was providing as much as 50 to 60 percent of total power generated from the main sources (Figure 4, left). During the freeze, natural gas fueled generation reached and exceeded 70 percent of total online capacity even with problems ranging from ice plugs in producing wells to equipment failures at processing and power plants. Coal plants were impacted by heavily iced storage piles of fuel.

Figure 6 below is the final image from a visualization of outages based on the same ERCOT timestamp data. Outages progressed generally from north to south with the storm track, placing pressure on wind first given the preponderance of facilities in the Texas Panhandle.

Crucially, the aggregation of generation outages while heating demand was affecting load meant a threat of complete grid failure. Early on February 15, frequency dropped below 60 Hz, "30 minutes of terror" as units tripped off simultaneously. This stressful period is depicted in Figure 7. It may come to be viewed as the finest hour for the unheralded grid operators since by their quick action ERCOT was able to avoid a system-wide blackout.

Estimates of the death toll in Texas, the most severely affected state, are estimated to have exceeded 200. Fatalities of any number are the most tragic result of this crisis. Outages of municipal water systems and telecommunications worsened the experience for the entire state. Local utilities' lack of preparedness for such large curtailments, and their inabilities to rotate the ordered outages among their residential customers, turned a challenging grid situation into a public emergency.

During the event, the PUCT took actions to address issues related to problems that it believed were causing the market to function improperly. Following ERCOT's EEA 3 the PUCT issued an emergency order, on February 15,[9] out of concerns that pricing was not reflecting the extreme conditions. The Commission's Chair stated that with the 10 GW of load shedding directed by ERCOT, scarcity pricing should be closer to the official $9,000 per MWh price cap currently in place rather than the $1,200 offer prices that the agency and ERCOT were seeing. Because generators were exceeding their maximum net margin revenue thresholds for peaking units, the PUCT suspended the low system-wide offer cap (the higher of $2,000/MWh or 50 times the natural gas price) that would otherwise have kicked in. These actions reflected concerns about natural gas prices, which had zoomed to nearly $24 per million Btu (MMBtu) in the Henry Hub index on February 17.

These steps, as well as a later action, to extend the pricing at the $9000 price cap until February 19, resulted in severe economic impact to the market that continues to reverberate. ERCOT's review captures the impact as shown in Figure 8. Apart from the offer cap and clearing, some ancillary services charges exceeded $20,000/MWh.[10] Bankruptcies and lawsuits, constituting billions of dollars in losses, reflect the combined efforts to procure natural gas and ensure continuous grid operations.

The Learning Curve

Evolution of the Texas competitive market has been well-documented.[11] Figure 9 is a snapshot of historical highlights for the U.S. and Texas. Current market rules and practices emanate from implementation of Texas Senate Bill 373 (1995)[12], Senate Bill 7 (1999)[13] and opening of the fully competitive retail market on January 1, 2002 along with changes since then, such as moving from the initial zonal to the existing nodal wholesale market design on December 1, 2010.

The point of restructuring was to foster a highly transparent marketplace that could convey price signals, allowing the discipline of interacting buyers and sellers to inform decision-making.

As winter 2021 events unfolded, many issues resulting from a number of early decisions in Texas market design have been debated in the press and among commenters.

- Texas' unique retail choice design extends choice to residential customers and requires education about risks and uncertainties associated with retail providers and their plans. Clearly, some customers on unhedged wholesale products, such as those offered by Griddy and others, may not have understood those risks.
- The focus on an "energy only" nodal marketplace for wholesale competitive supply and pricing leads to questions about whether revealed prices are sufficient to ensure capacity and reliability during high demand periods, especially when the system is stressed.
- Municipal utilities and cooperatives were free to decide whether to "opt in". This created a heterogeneous landscape of fully competitive resource entities co-existing with fully regulated ones. The costs of the event fell very differently on those in competitive and regulated part of the state.
- Fragmentation among the many different institutions that have stakes in the Texas marketplace – the PUCT, RRC, ERCOT, the Texas Reliability Entity (Texas RE, see previous Figure 9) along with federal bodies such as the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Council (NERC) and more, including local county and city governments and organizations, meant that no one entity had a true understanding of the complexity of the system
- In all, ERCOT remains a separate interconnection. Would interconnections to other U.S. regions have helped? Other parts of the region were facing similar stresses, so this widespread complaint, which surfaced early in the progression of the freeze, is difficult to assess.

Importantly, policymakers at the PUCT, the RRC, and the Legislature had warnings from prior incidents of large scale outages and associated reviews, in particular disruptions during winter 2011[14], but left many recommendations insufficiently unaddressed. The 2011 outage involved about 5,000 MWs curtailed over a seven hour period as opposed to the much greater impacts experienced in February 2021. However, as one of us wrote in 2011[15], failure of the industry to own up to root causes could lead to another major outage.

Wholesale Competition

Was Texas competitive market design a factor in the outage? One take is to compare performance between competitive and regulated resource entities. We separate "resource entities" that do not have wind or solar (with one exception as noted) from those that *only* engage in those products. We separate municipal utilities and electric cooperatives that remain fully regulated monopolies. The 12 resource entities used in Figure 10 represent about 60 percent of nameplate capacity within ERCOT. The result indicates a wide range of performance with respect to outages and, implicitly, underlying portfolios and management practices[16]. In general, the resource entities that remain fully regulated performed less well even excluding a strong outlier.[17] For all resource entities the financial incentives to perform were very strong.

Pricing and Market Design

In the past decade, Texas has debated whether to institute a formal capacity market. A common argument has been that energy-only, real time pricing cannot provide sufficient incentive for long-term investments.

During February, ERCOT's issue was not the lack of capacity but rather that its *planned* capacity could not deliver due to *unplanned* outages. A capacity market could not have solved this problem as the 2014 "polar vortex" in PJM has shown. Moreover, the $9,000/MWh price is much more powerful than penalties usually found in capacity market designs.

After the 2011 winter event, the PUCT adopted the operating reserve demand curve (ORDC) as a more surgical way to spur economic investment. The ORDC effectively adds a ramp-up in price to what would otherwise be a vertical price/demand curve. As demand approaches available capacity, an administrative adder is applied to the market clearing price to send an earlier, stronger price signal for demand to curtail and for supply to be available.

One factor affecting the robustness of the energy market is the volumetric production federal income tax credit given to wind energy. Much of Texas wind output receives a federal $23/MWh production tax credit (PTC) subsidy. This is roughly the overall clearing price for power in the ERCOT energy market, making the federal subsidy material. As opposed to the solar investment tax credit, which is an offset to capital expense, the ongoing PTC is reflected in every MW-hour sold for ten years after a wind plant is built.

Arguments related to distortions associated with wind and PTC treatment are well trod ground.[18] In any case, the jury is still out on whether the ORDC has resulted in new investment in new thermal generation and storage capacity.

REPs and Their Products

The retail competitive market is a separate issue. Most retail customers choose bilateral fixed price contracts, providing predictability around pricing and cost. Almost all residential customers in the customer choice regions of the state were largely unaffected by the wholesale power costs of the February outage. Similarly, many commercial and industrial users had price protection through their negotiated contracts. The impact on their competitive providers, however, varied widely, depending on how well those providers were able to manage procurement and hedge risk. Several REPs did not have the wherewithal to absorb high costs for power and ancillary services[19] and represent some of the bankruptcies and litigation progressing through Texas courts. One such REP referenced earlier, Griddy, received considerable notoriety[20] because its roughly 10,000 customers chose to be directly exposed to wholesale market pricing as compared to roughly seven million statewide that use fixed rate contracts from other REPs.

In contrast, regulated municipal and cooperative monopolies, which serve about one-sixth of ERCOT customers, almost certainly will be allowed to pass through most or all of their fuel and power costs to their captive ratepayers. The Texas Legislature passed laws enabling the securitization of such costs at lower interest rates by electric cooperatives and regulated gas distributors for up to 30 years. So there is a difference in how risk is borne in competitive and regulated retail markets.

Operational Dilemmas

Operational challenges are the first problems to solve. Past experience during previous outages in 2011, 2003 and before should provide lessons. As we suggested earlier, they may also offer low hanging fruit in possible fixes that were identified, such as during the 2011 review, but not yet implemented. The winter 2021 event represented a significant loss of supply from the statewide pool, and a much lesser than expected outage due to iced-over poles and wires, making it unusual.

The harsh lesson from these experiences is the need to learn to expect unexpected, plan for unexpected, and be able to make systems work through events no one expects. None of this is easy, but a first step is to identify and work on what was inoperable. For the 2021 experience, the natural gas system is a place to start.

Natural Gas and Gas-Electric Harmonization

The preponderance of outages in Texas, including significant events, are during winter. And yet, for obvious reasons, most of the planning and focus in ERCOT has been on hot summer months. Natural gas prices are a clue to relative stress. With some exceptions, hot weather and hurricanes have much less impact on gas supply and pricing than winter shortages (Figure 11). Rapid escalation in natural gas prices and costs are felt across the U.S. as diminished flows in interstate pipelines remove gas from end use markets. Based on industry information, interstate pipeline throughput dropped by as much as 80 percent in some cases.

Many unanswered questions persist about the performance of the natural gas system during the February event. Reports of delivered gas costing several hundreds of dollars per MMBtu, orders of magnitude above normal winter pricing, raise red flags.[21] Sharp increases in price mainly are symptomatic of bottlenecks, of which there were many. It can also be that the boundaries lie around who had gas to sell, with ability to ship and deliver it, and whether receiving customers had contracted sufficiently for their fuel resources in advance.

Deeper questions revolve around the very strong interplay between natural gas, which supplies well over half of ERCOT power generation at peak and on an annual basis, and electric power. These are two very different systems – an extremely transparent five minute, around-the-clock market for power and grid balancing in contrast with a gas industry which operates five days a week during business hours with no night trading, and month ahead nominations for pipeline capacity to deliver supply. Among the lowest hanging fruit is greater awareness among utilities that natural gas is critical fuel for their generation. Oncor, the state's largest utility, pre-event, had classified 35 gas facilities as critical (and therefore not to be curtailed during any controlled outages). Post event, Oncor added an additional 168 facilities to the list.[22]

The trick is how best to integrate two such different industries and systems as much as possible.[23]

One underlying factor has been the trend toward using grid-based electricity, made cheap by abundant low cost natural gas, to provide energy for field operations and the natural gas delivery system.[24] Experiments with other approaches for producing fields are still nascent. Unknown is the effect of the $9,000 price cap on these practices going forward. At the minimum, standalone, backup power supply would offset risks from interdependencies.

Weatherization

Weatherization is a system issue related to natural gas, although plenty has been written elsewhere regarding wind, coal-fired and gas-fired power generation facilities. Recommendations for winterizing natural gas production and midstream were made in the 2011 post-event report. Estimates on the cost of weatherization down to the wellhead vary widely with some reports indicating that it can be done cost effectively and others indicating that it can double the cost of completions.[25] A recommendation for exemptions from rolling blackouts for critical natural gas facilities has struck a chord given confusion last February regarding the RRC and electric utility process for making and fielding these requests.

Planning

What steps could have been taken to better prepare the public?

Given that the larger, more widespread outage events occur in winter, a "hurricane level" of preparedness could become the norm. Images of brightly lit commercial buildings when households were without power (or water or telecoms and internet) grated. A more granular system to manage rolling outages could address what became, ultimately, a public safety catastrophe.

What of the key institutions? As we complete this article, the Texas Legislature – which meets every two years – has passed legislation to address some of the key issues raised by the February outage. After an initial flurry of proposals, bills[26] related to the outage settled into more pragmatic approaches to improve emergency preparedness (alerts and backup power at health facilities), mandate winterization for power plants and natural gas facilities, and allow ratepayer-backed bonds and loans for gas and power companies. As the winter freeze tightened its grip, ERCOT governance came under immediate scrutiny. A smaller, but now fully independent, ERCOT board will be selected by a trio of political appointees. Regulators must now review whether sufficient reserves are available for wind and solar or if more are required.

Should all of the infrastructure industries come under one regulatory roof? As attractive as this idea might be for within-state planning and coordination, it is unlikely.

What of the federal jurisdiction? The Texas RE remains controlled by NERC and Texas remains a NERC electric reliability organization (ERO)[27]. In 2005 mandatory reliability standards were made applicable across all of the U.S. No carve out for Texas or ERCOT was granted. The Texas RE, charged with monitoring compliance with mandatory standards, was broken out of ERCOT to ensure independence and is being deployed by FERC and NERC for their investigation of 2021 events.

Positioning for the Future

In all, the 2021 winter storm represents classic tail risks and associated economics – high consequence but low probability events, expensive to "insure" against. However, with at least three major events over the last two decades (2003, 2011, 2021), it is becoming increasingly clear that these are not classic tail events and that policymakers must act to address what has become common occurrence.

A related, and perhaps even more intriguing issue, is the implication from the 2021 experience for the state's, and nation's, energy future: how to balance the imperative for using the grid as a tool for decarbonization while maintaining high levels of reliability.

In its 2020 report on reliability[28] NERC pointed to the assorted risks emanating from increased investment in wind and solar facilities. These generation resources have variable output and performance, and government subsidies can distort energy market pricing. Still, they are expected to increase in share of power capacity and production, although there is some public opposition to essential transmission improvements. Wind, solar, batteries, electric vehicles represent geopolitical exposure stemming from international supply chain risks and disruptions.

Let it be said – Texas is a big state, attracting migrating businesses and residents on a net basis every year. Population and electric power demand have grown in tandem, but year to year changes in electricity sales reflect recessions and other events that encumber electric power planning. One of the more significant differences across historical outage events is simply the larger number of people, households and businesses that are impacted over time.

Even as Texas adds new sources of generation, the challenge is to figure out how to facilitate the flow of wind, solar and storage while ensuring reliability during the hottest summers and coldest winters. Fossil fuels and nuclear are too important to dismiss. In an intriguing mandate to the PUCT to study and act on dispatchable generation, the Texas Legislature recognized the need to plan for the future with these resources in mind.[29] High demand periods lead to financial consequences that cannot be minimized, otherwise power systems are not economically sustainable. New technology is desirable –smart meters, distributed energy resources like rooftop solar, flexible energy storage and much more. The challenge is to enable these attractive technologies to more fully enhance reliability.

No models exist in any part of the world to guide development of the power grids of the future. Texas is the front line, making the learning curve an imperative.

Article endnotes and figures available online at: https://www.iaee.org/newsletter/issue/109.

Highlights of IAEE 2021 Online Conference's Main Sessions

BY NICOLÒ ROSSETTO AND JEAN-MICHEL GLACHANT

On 7-9 June 2021, the International Association for Energy Economics (IAEE) organised its first online conference, gathering almost 1000 attendees and 600 speakers in more than 150 sessions. It was a unique opportunity to understand what are the topics most debated in energy economics and get a comprehensive overview of what is the state of the art. The Florence School of Regulation (FSR) and its researchers closely followed the conference, providing the audience with comprehensive coverage of several sessions on Twitter. A series of highlights on each of the main sessions was published close to real time. In what follows, we reorganise these highlights into six short blocks.

Energy access

Despite recent progress, we are still far from achieving Sustainable Development Goal n. 7, i.e. to ensure access to affordable, reliable, sustainable and modern energy for all. In many parts of Africa, but also Asia and other continents, energy access cannot be taken for granted yet. Academic research on the topic is growing, but still much remains to be done. In particular, scholars must look at the implications of the local context and develop policy recommendations that take into account the significant heterogeneity in framework conditions characterising countries with energy access issues: no silver bullet exists. Contrary to the expectations of many, energy distribution looks like one of the most problematic elements of the supply chain and the one responsible for unsatisfactory progress in energy access in several places, as for instance India. Distribution requires large investments, but flawed regulation that does not ensure adequate cost recovery often hinders public and private initiatives. The result is unreliable energy supply even if sufficient generation capacity is available. Some scholars have recently proposed an integrated distribution framework that suggests the use of alternative strategies to ensure the distribution of energy, depending on the different local conditions (e.g., grid expansion vs mini-grids development). Applied research and experience from the field finally highlight the importance of adequately consider the political landscape and the complexity of policy implementation: in many countries around the world, power and politics are closely intertwined.

This topic was mainly addressed in the morning parallel session 2.1, "Energy access around the world". To know more about the content of that session, you may listen to the interview with Anna Creti (University Paris-Dauphine) by Swetha RaviKumar Bhagwat (FSR).

The incumbents: oil, natural gas and nuclear

The energy transition challenges the role of the main sources in the current energy mix. This is true not only for coal, but also for oil, natural gas and nuclear. The growing political support for the reduction of greenhouse gas (GHG) emissions and the rapid development of clean technologies imply that 'incumbents' will have to adapt. However, the way and pace at which change will take place are unknown. Uncertainty is dominant. For instance, according to certain scenarios oil demand may have already peaked, while according to others, it will continue to grow for several more years. In this context, companies have to develop contingency plans and governments have to take clear policy decisions that provide consistent signals to stakeholders and investors.

Oil and gas companies could try to reduce uncertainty about their future prospects by focusing on cost and emission reductions, developing reserves with a shorter time to market, shifting their business towards petrochemicals, and investing in low-carbon technologies like carbon capture, utilisation and storage (CCUS), hydrogen and other 'green' gases. A reduction in methane emissions along the entire supply chain represents the low-hanging fruit that oil and gas companies could achieve in the short to medium term, often in a cost-effective way. Governments in oil and gas producing countries should act as well and streamline their efforts in the diversification of their economies and the management of strandable assets. This is particularly relevant for major exporters like Saudi Arabia.

In the case of nuclear, the need for rapid and deep decarbonisation of the energy mix could open a window of opportunity for re-launching a low-carbon energy source whose relevance has shrunk over the years in many advanced economies. This may have positive implications in terms of local employment and security of supply. However, the risks associated with the use of nuclear energy in liberalised electricity markets require a strong and credible commitment by policymakers.

Several sessions of the conference addressed these topics. Among them, afternoon parallel session 1.2 "The role of gas in energy transition", afternoon parallel session 3.1, "Oil in times of energy transition", and afternoon parallel session 3.2, "The role of nuclear in decarbonisation strategies". To know more about the content of those sessions, you may listen to the interview with Olivier Massol (IFP School) by Maria Olczack (FSR), to the interview with Adam Sieminski (KAPSARC) by Mohamed Hendam (FSR), and to the interview with Michel Berthélemy (OECD NEA) by Nicolò Rossetto (FSR).

Hydrogen as a novel energy vector

Hydrogen plays a minor role in the energy sector today, but it has gained significant attention over the past few years due to the possibility of using it to reduce the cost of future decarbonisation and utilise some already existing infrastructure. Hydrogen production, today mostly derived from the reforming of natural gas, is expected to grow significantly in the next decades and increasingly relies, under certain assumptions, on the use of electrolysers, which turn electricity and water into oxygen and hydrogen. Consumption is assumed to increase many times as well, mostly in transport and industry. Hydrogen looks suitable to many applications, either as a feedstock or as an energy vector that can be easily stored, contributing to better and more efficient integration of intermittent renewables like wind and solar (power-to-hydrogen and hydrogen-to-power). However, there is a widespread acknowledgement that some conditions must be satisfied. First, public support and favourable regulation are necessary for the coming years to foster research and development (R&D) activities and kick-start the deployment of hydrogen assets. Second, improvements in technology are fundamental to ensure cost-competitiveness. They are likely to materialise via breakthrough innovations as well as learning by doing. Thereby, economies of scale in the production and consumption of hydrogen matter. Finally, exploitation of renewable energy sources must grow in order to generate cheap electricity that allows the production of hydrogen at low costs (developments of CCUS and nuclear can also positively affect the outlook for hydrogen, but the use of those technologies is more debated). The importance of electricity prices highlights the role of hydrogen as an enabler of sector coupling, a development that calls for further economic and regulatory research.

This topic was addressed in several sessions of the conference. Among them, the keynote session on day 2, “The future of hydrogen”, and morning parallel session 2.2, “Power-to-hydrogen and hydrogen-to-X”. To know more about the content of those sessions, you may listen to the interview with Marina Holgado (IAE) by James Kneebone (FSR).

New Trends: local governance, circular carbon economy and shared electric vehicles

The transition towards a more sustainable energy system entails the abandonment of many elements that characterise current energy systems and the emergence of new trends.

First, a growing role of the local dimension and its governance. The decentralisation of the energy system means that a higher share of energy is produced and delivered at the local level. This is particularly visible in electricity, where the deployment of solar PV, wind turbines, small-scale gas turbines, domestic storage and the like results in many kWh never leaving the distribution grid in which they are injected first. In this context, the role played by distribution companies is changing and becoming key to the effective and efficient activation of customers. In many parts of the world, distribution companies are aware of that and are often enthusiastic about their growing centrality; however, they frequently struggle to address contrasting societal goals, as for instance the mandate to be cost-effective and at the same time treat all customers in a fair way. Distribution locational marginal pricing has been proposed in this regard as a solution to foster the coordination of investment and asset operation at the distribution level, by providing every user of the network with a detailed signal about the costs his or her decisions mean for the system. However, practical implementation has been so far almost non-existent due to technical challenges, public opposition and a difficulty to convey a clear and palatable message to retail customers. Appropriate pricing of local resources is not the only challenge local governance must confront with. Growing local opposition to the construction of any new infrastructure, including renewable power plants, represents a serious issue that may hinder the achievement of net-zero (NIMBY syndrome). Innovative and inclusive approaches that expand ownership in new infrastructures and the abandonment of a litigious legal culture are important steps in a broader strategy to speed up the energy transition.

Second, the replacement of the classical linear and sectoral approach to energy with a circular and cross-sectoral one. Climate change calls for the use of all the available tools and levers. No single solution is likely to be cost-effective and acceptable to every stakeholder. In this context, the circular carbon economy (CCE) is a new approach that builds on the principles of the circular economy and applies them to carbon emissions. This approach, recently proposed by Saudi Arabia and endorsed by the G20, aims to be holistic, integrated, inclusive and pragmatic. It is based on the ‘four Rs’: reduce carbon emissions; re-use carbon as an input to produce feedstock and fuels; re-cycle carbon via natural carbon cycles and bioenergy; and remove excess carbon from the atmosphere and store it geologically. Adopting this approach can represent a step forward in the active involvement of countries with large fossil fuel reserves in the fight against climate change. However, more thinking and technological investigation is needed to beef up the CCE concept.

Third, a new culture of mobility based on shared electric vehicles. The established view that privately owned cars running on fossil fuels satisfy best individual mobility needs represents a major obstacle to the transition towards a sustainable energy system. Private passenger cars are a significant and rising source of GHG emissions, remain idle most of the time, and constitute a substantial cost for families and society at large. Today, technological development and digitalisation offer new opportunities that can be cleaner, safer and more convenient. If managed in a smart way, EV fleets can provide valuable services not only to passengers but also to the electricity grid (vehicle-to-grid solutions). However, changing entrenched habits and established infrastructures by investing in expensive new assets is not easy. Therefore, governments have an essential role to play in promoting the uptake of a new mobility culture.

Several sessions of the conference addressed these topics. Among them, afternoon parallel session

1.2, "Shared autonomous electric mobility: triple revolution", afternoon parallel session 2.1, "Energy transition and local governance", and afternoon parallel session 2.2, "Circular carbon economy". To know more about the content of those sessions, you may listen to the interview with Ramteen Sioshansi (Ohio State University) by Golnoush Soroush (FSR), to the interview with Michael Pollitt (University of Cambridge) by Athir Nouicer (FSR), and to the interview with Noura Mansouri and Adam Sieminski (KAPSARC) by Maria Olczak (FSR).

Hybrid markets for electricity and carbon pricing

The energy transition requires a massive amount of physical investments in low carbon technologies. An adequate market design and long-term price signals are necessary to provide investors and market participants with the right incentives. In the case of electricity, there is a growing consensus among scholars that short-term energy only markets (EOM) cannot do the job alone. Introduced in the 1990s and 2000s when the new dominant technology was represented by combined cycle gas turbines running on natural gas, EOMs provide incentives for an efficient operation of existing generation capacity, but appear less capable of stimulating the necessary investment in new capacity, especially when generation technologies are highly capital intensive, as it is the case with nuclear and many new renewable energy sources. The political commitment to a rapid decarbonisation of the electricity generation mix only exacerbates the issue and suggests the need for a rethinking of electricity market design and the adoption of some 'hybrid architecture', capable of providing sufficient long-term signals while preserving the short-term incentives that EOMs produce. There are already some early attempts to provide a coherent theoretical framework, but the details of how a hybrid market should look like are still subject to investigation. Nevertheless, it seems clear that reaching net-zero in less than 30 years cannot be done with uncoordinated patches on current electricity market designs.

Pricing carbon so that externalities in its production are duly considered when assessing investment choices is an important policy tool that is gradually gaining ground around the world. Today, more than 20% of the CO_2 emissions at the global level are subject to some form of explicit pricing, either via a tax or as part of a tradable quota system. These pricing mechanisms incentivise the use of low-carbon technologies and provide governments with an additional source of revenues. However, the future of carbon pricing is uncertain and the role of researchers in this field is far from exhausted. High carbon prices, as those required to foster the decarbonisation of our economies in the coming decades, have important distributive implications. Since they generate winners and losers, at least in the short to medium term, they tend to be politically sensitive. They also interact with other public policies like support mechanisms for renewables or the general taxation system. Therefore, any meaningful assessment of carbon pricing cannot occur in isolation, but must consider these additional dimensions. Finally, the need to expand the outreach of carbon pricing and cover economic activities that were previously exempted calls for new research efforts capable, in particular, to highlight the barriers that may limit the effectiveness of the various carbon-pricing mechanisms.

These topics were mainly addressed in morning parallel session 1.1, "The future of carbon pricing", and in morning parallel session 1.2, "Hybrid market architectures for ensuring investments in the European electricity sector". To know more about the content of those sessions, you may listen to the interview with Jan Horst Keppler (University Paris Dauphine) by Tim Schittekatte (FSR).

Energy transition

Energy transition represents today the *fil rouge* connecting most of the issues addressed by energy economists. It constitutes a massive challenge for the energy sector and society at large. A consensus on the need to deeply decarbonise the economy by 2050 in order to mitigate climate change is now well established, but the specific policies and the implementation pace of those policies are subject to intense debate and alternative views are apparent. This situation is often the natural consequence of the different conditions and interests, characterising different countries, industries, companies and people. The enormous transformations that the energy transition entails inevitably present relevant costs and a significant redistribution of wealth. Not everybody will be affected in the same way. At least in the short and medium term, it is likely that we will have winners and losers. This explains the enduring disagreement about the most appropriate policies to adopt and their timing.

Nevertheless, there is a growing understanding that concrete and far-reaching measures must be taken now. Waiting another few years would only narrow the already demanding pathway to net-zero and increase its cost. In particular, continuing to invest in carbon-intensive technologies today risks intensifying the problem of stranded assets and the need for an even larger and faster re-allocation of capital and labour in the coming decades. Indeed, the profound restructuring of the economy that deep decarbonisation implies unequivocally calls for a significant role by governments. They are expected to 'guide' the transition by coordinating or guaranteeing the economic decisions of companies and customers, by supporting financially much needed investments in R&D and early deployment of clean technologies (either directly or indirectly, as the financial industry seems ready to act), and by ensuring that nobody is left behind. Leaving the job to competitive markets alone, with no clear signal or credible target, is less and less considered a choice compatible with the timing and the scope of the energy transition.

Policymakers should take bold, constructive and realistic decisions. Those decisions must be credible and this, in turn, requires consistent choices and measures that adequately consider those that are worse off due to the transition and those that do not have the economic resources to afford it. Solidarity must be a guiding principle at the domestic and international level. Coordinating decarbonisation strategies across borders is essential to address climate change, but we should shy away from the idea that there is only one road to net-zero. Given the uncertainty regarding future technological developments and the different situation in the various countries around the world, alternative approaches are possible and worth to be explored. Continuous interactions among policymakers and further research by scholars and practitioners will allow, over time, to identify and possibly converge on the best solutions to the challenges of the energy transition.

Several sessions of the conference addressed this topic. Among them, the opening keynote on day 1, "Energy transition in times of Covid", morning parallel session 3.1, "The future energy mix", morning parallel session 3.2, "Lessons from leaders in energy and climate policy", the concluding keynote on day 3, "Shaping a clean energy future after Covid", and the closing plenary session on day 3, "The new energy landscape". To know more about the content of those sessions, you may listen to the interview with Yannick Perez (Centrale Supélec) by Nicolò Rossetto (FSR), to the interview with Keigo Akimoto (RITE) by Piero Carlo dos Reis (FSR), to the interview with Christophe Bonnery (Enedis) by Tim Schittekatte (FSR), and to the interview with Yukari Yamashita (Institute of Energy Economics, Japan) by Swetha RaviKumar Bhagwat (FSR).

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Call for Newsletter Articles

The current transition to renewable and sustainable energy represents a significant change in our energy systems. Germany's Energiewende, the push towards EVs, conditions for development of decentralized generation, and energy efficiency and other initiatives are all looking to reduce the global reliance on fossil fuels and reduce greenhouse gas emissions.

We are interested in how energy transitions are moving forward around the world. What is working, and what challenges lie ahead? We call for you to share how, (and what and when,) energy transition is affecting you in your geographic locale and are soliciting articles representing all aspects of energy transition.

If you are interested in submitting an article (non-technical in nature) for the Energy Forum on these topics, please email iaee@iaee.org. Articles should be between 750 and 3000 words and submitted in MS Word. Please make sure to include a short (50 words or less) capsule/abstract that overviews the article with your submission.

We need your article for consideration no later then Friday, September 3.

Climate and Power System Reliability in the Aftermath of the Texas Blackouts

BY MARIE PETITET, BURCIN UNEL, ROLANDO FUENTES, AND FRANK A. FELDER

Abstract

The February 2021 blackout in Texas underscored the importance of reliable and resilient power systems. This article discusses the roles of regulators, markets, fuel and generation supply chains, and interdependent infrastructures, and finds that they need to be reconsidered and redefined to successfully meet the future challenges of increased electrification and severe weather.

Introduction

Climate change and severe weather are stressing power grids, while climate change policies are increasing the role of electrification in transportation, heating, and industrial processes. The February 2021 catastrophic blackout in Texas underscored the importance of reliability and climate resilience, and raises questions regarding the roles of markets, the grid and fuel supply weatherization, renewable energy sources, transmission interconnections, and regulatory structure in the electric power industry. This event occurred during a cold snap that brought temperatures in Texas to lows not seen in more than thirty years, with millions of people losing power and tens of people losing their lives.

The policy response to severe weather and the industry's changing generation mix should be based upon the engineering and economics of the grid, integrated across regulatory and market policies, and extended beyond the power sector. This paper provides an overview of how reliability has been addressed in power systems and identifies key challenges for the future.

We raise the following questions:

- Instruments: Are the instruments that we currently have at hand (feed-in tariffs, capacity markets, fixing value of lost load [VOLL], etc.) sufficient to solve the resource adequacy problem in case of more frequent extreme events?
- Regulation: Given that the impact of extreme events caused multiple parts of the electricity system to fail at the same time, along with natural gas production and delivery, is it time to coordinate regulation of both sectors to improve reliability?
- Mitigation versus adaptation: Mitigation and adaption are complementary in their responses to climate change. However, since policy instruments that promote the deployment of renewables (emissions mitigation) may increase the impacts of extreme events (adaptation), how should these two issues be reconciled?

Important Preliminaries: Climate change, severe weather, blackouts, and generation markets

Climate change affects weather patterns, including potentially contributing to severe weather events. However, it is not possible to connect any individual weather event to climate change (Chandramowli and Felder, 2014). Recent examples of extreme weather in the United States (U.S.) include polar vortexes in the north and mid-Atlantic states, extreme hot and cold weather in Texas, and hurricanes along the Atlantic coast. Common cause failures such as severe weather can result in widespread equipment failure of generation, transmission, and distribution components, resulting in widespread and long-term power outages. For instance, the severe cold weather in Texas in February 2021 prevented large amounts of conventional and renewable generation from producing electricity. On the other hand, hurricanes can result in widespread failures of distribution components.

A reliable electric system delivers electricity to consumers in the desired amounts, and a resilient system quickly recovers from power outages and mitigates the impacts of power losses. The electric sector is intertwined with other critical infrastructures, and they need to be able to collectively adapt to blackouts by providing critical services, such as heating, cooling, communications, public safety, and health care, during power outages.

Distribution and transmission systems are regulated. That is, regulators determine the levels of investment, the rates, and the quality and reliability of service that a regulated monopoly or government-owned utility provides. Generation is provided through a wholesale market (and possibly a retail service, as in Texas, which consists of electricity procurement services). Whether Texas' wholesale market design played a significant role in the recent blackouts is an issue of contention, but it is only a part of a broader question of what the roles of regulation and markets are in achieving reliability and resiliency in the power sector.

Texas and its 'Energy-Only' Market

Texas' electricity 'energy-only' market design was considered a role model of electricity reform by many

Marie Petitet is a Senior Associate with KAPSARC. **Burcin Unel** is the Energy Policy Director for the Institute for Policy Integrity, New York University School of Law. **Rolando Fuentes** is Research Professor of Economics and Finance for EGADE Business School and Visiting Researcher, KAPSARC. **Frank A. Felder** is the Program Director for Energy Transitions and Electric Power, KAPSARC. Frank Felder can be reached at: frank.felder@kapsarc.org

until February 2021, and reflective of the state's market orientation. The Electric Reliability Council of Texas (ERCOT) operates the grid, while power generators produce electricity for the nodal-pricing wholesale market, and some 300 retail electricity providers compete for retail consumers.

The ERCOT model is close to the theoretical energy-only model. Its generation shortage pricing mechanism is designed to provide one important component of reliability: adequate generation resources to supply load. In a theoretically-ideal energy-only market, the value of loss load (VOLL) and loss of load probability (LOLP) would be set by the market. Instead, the VOLL is prescribed by regulators and the LOLP is calculated by ERCOT. Still, Texas has enjoyed lower average electricity prices than the U.S. since it liberalized its electricity market in the early 2000s (in part due to its wholesale market, but also due to its abundance of natural gas).

Because the cold weather observed in February 2021 in Texas is relatively infrequent, natural gas production and delivery companies have not invested in winterizing their equipment. Adding a further complication, in 1999 the state set targets for renewables, which now constitute roughly 25% of Texas' generation capacity, almost all of it wind. Wind and solar photovoltaics are variable, limiting their ability to balance supply and demand, which power systems must do continuously to avoid blackouts. Furthermore, ERCOT can only import small amounts of electricity from other regions, severely limiting neighboring regions from providing emergency power. However, this ensures that very little of Texas' electricity market is subject to U.S. federal regulation.

Given ERCOT's context, the following are some immediate policy solutions to the widespread blackout:

- Increase the VOLL.
- Incentivize winterizing equipment by creating mechanisms that incentivize (either through penalties or benefits) companies foregoing short-term profits to ensure their equipment withstands extreme weather.
- Assess the relevance of creating a capacity market or establishing a mandatory capacity requirement. This mechanism should consider extreme weather events carefully and incentivize the winterizing of equipment.
- Increase interregional trade by investing in interconnections with other grids.
- Promote grid storage to increase the ability of renewable generation to contribute to balancing supply and demand.

These approaches would essentially act as an insurance policy against the lights going out. The costs of implementing these policies would be borne by retail electricity consumers in exchange for improved reliability in normal times, and mitigating problems caused by relatively rare extreme weather. Taking these actions, however, might also interfere in a market that functions well the rest of the time. This tradeoff might change should extreme weather events become more frequent, more severe, or with longer durations due to climate change. The latter scenario would require a change in the current market-regulatory framework, necessitating policies beyond the immediate solutions given above.

A counterintuitive proposal might be to deepen market approaches. Although reliability is a main goal for system operators, there are multiple degrees of reliability depending on the frequency, magnitude, and duration of outages. For instance, a once-in-a-decade cold snap or heatwave that causes a few hours of rotating blackouts may be something that can be lived with. As the Texas crisis reveals, however, multiple days without power and heat during sub-freezing temperatures cause very high costs in terms of lives lost and economic damage. Between these two scenarios, there are many alternative options that combine technological solutions, prices, costs, and consumer preferences. Given the new nature of extreme weather problems, what combination of planning, technological, and market solutions should be pursued?

Other Market-Based Methods to Address Resource Adequacy and Climate Change

Energy markets are considered the cornerstone in enabling the cost-effective use of existing generation units (short-term dispatch role) and guiding long-term investments due to infra-marginal rents (Caramanis et al., 1982). In practice, many concerns have been raised about (i) the ability of these markets to sufficiently invest in capacity adequacy (Jaffe and Felder, 1996; Joskow, 2006; Keppler, 2017; Petitet et al., 2017) and (ii) their effectiveness to deal with energy transitions (Finon, 2013; Peng and Poudineh, 2019).

Regulators, whose main objectives are to provide secure, affordable, and environmentally friendly electricity to all residents, want to avoid large blackouts, such as the recent one in Texas, and facilitate the transition to low-carbon energy sources. To this end, many regions have decided to implement additional mechanisms that have been specifically designed to tackle adequacy or mitigate climate-change issues, beyond an energy-only market. Figure 1 provides an overview of implemented and proposed mechanisms with their key characteristics: quantity versus price-based; centralized versus decentralized; targeted versus capacity-wide for capacity mechanisms; and technology-neutral versus technology-specific for support mechanisms.

Ensuring resource adequacy

Resource adequacy is generally treated as a public good and, thus, is handled by regulators or governments. To ensure adequacy, some advocate that the energy-only market can be enhanced to avoid missing money without the need of any additional mechanism (Hirst and Hadley, 1999; Hogan, 2005). Others propose introducing capacity mechanisms to complement the long-term coordination that power systems require (Jaffe and Felder, 1996; De Vries, 2007; Cramton et al., 2013). Many global regions have

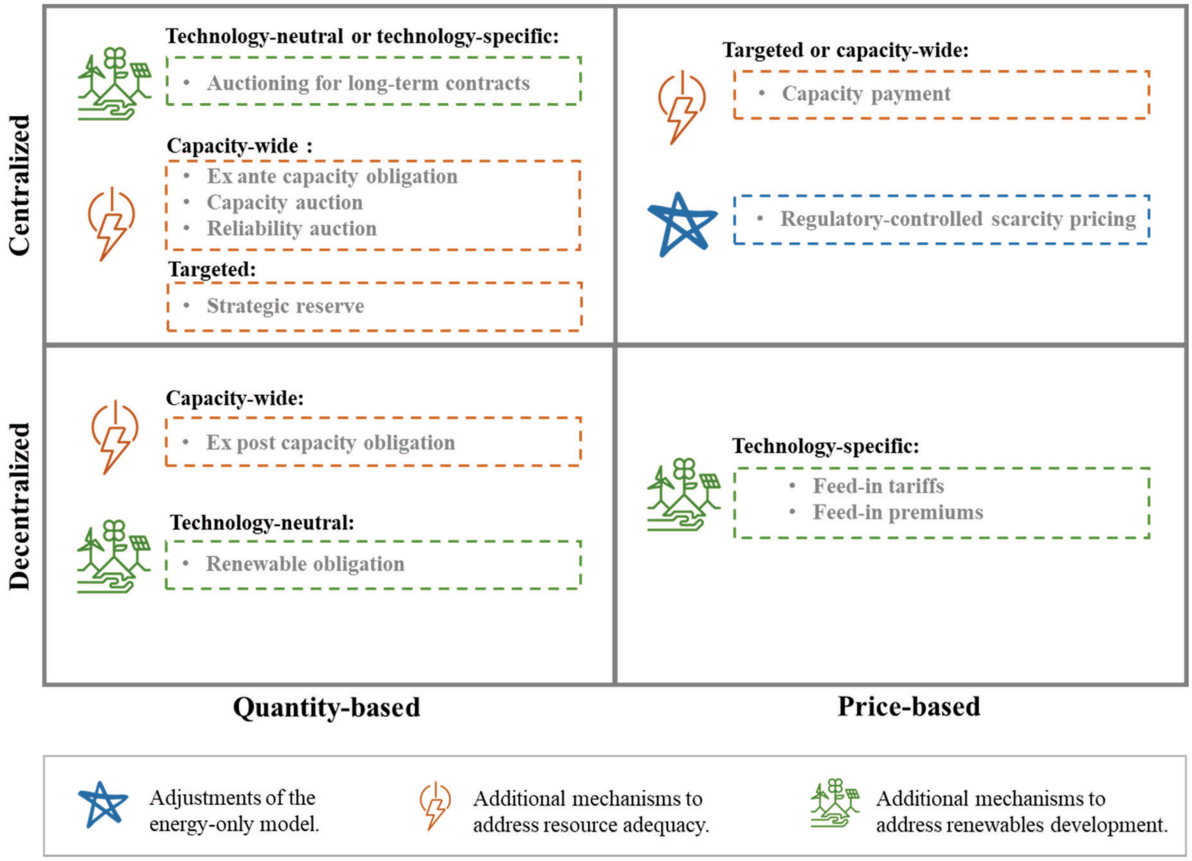

Figure 1:Overview of adjustments or additional mechanisms in liberalized power systems

already implemented capacity mechanisms to deal with resource adequacy, such as in the U.S. (PJM, ISO-NE, and NYISO), the United Kingdom, France, and Poland. However, no country has yet dealt with its grid's resilience to climate change.

Once implemented, resource adequacy should be evaluated based on possible future relevant scenarios, including geographical scope, and weather and climate assumptions. In particular, extreme weather events and climate change effects should be carefully considered. Adequacy studies of the French power system will be carried out, with future scenarios based on Intergovernmental Panel on Climate Change (IPCC) assumptions until 2050 (RTE and IEA, 2021; RTE, 2021). Following the European Commission's recommendation, the European Network of Transmission System Operators for Electricity (ENTSO-E) is working on enhancing its methodology for adequacy studies in Europe (ENTSO-E, 2020).

Tackling climate change and energy transitions

Renewable energy sources of electricity (RES-E) are rarely developed based solely on energy market signals. These technologies have been identified as key solutions to decreasing carbon dioxide (CO_2) emissions from generation, while providing other benefits for governments such as energy independence and job creation. To foster RES-E deployment despite their limitations, many countries have implemented specific support mechanisms, as presented in Figure 1.

Renewable obligations prevail in the U.S., and feed-in tariffs prevail in Europe. Both are decentralized, and they incentivize RES-E projects while allowing RES-E to participate in energy and balancing markets as conventional technologies do. In many countries, RES-E support mechanisms have been implemented in addition to pre-existing carbon pricing, which, unlike RES-E, has not necessarily been limited to the power sector. Carbon pricing has not been sufficient to drive investments in RES-E due to, in part, political concerns surrounding high electricity prices. Though renewables were being developed to mitigate climate change, they could paradoxically contribute to magnifying the impacts of extreme events, and thus reinforce the importance of adaptable and resilient power systems.

Early on, many regulators preferred feed-in tariffs because they are relatively simple to implement. However, recent history has shown that dramatic, unexpected effects can arise when RES-E are out of the market, including episodes of negative and highly volatile wholesale prices. Thus, recently more attention has been paid to enhancing the functioning of support mechanisms by increasing the participation of RES-E in energy and balancing markets.

Multiple-layer power systems and interactions between mechanisms

Many power systems are far away from the theoretical energy-only model. Energy markets are complemented by multiple layers of capacity mechanisms, RES-E support schemes, and other support schemes for specific technologies (e.g., zero-emission certificates for nuclear power). As initially proposed by economists, energy markets were supposed to provide long-term signals for investors. In practice, investors face a much more difficult forecasting exercise that includes predicting energy prices and the interactions between and outcomes of the additional capacity mechanisms. For instance, introducing a minimum offer price rule[1] (MOPR) in U.S. capacity markets changes the remuneration structure of renewable power by removing its capacity revenue and increasing the REC price to ensure its profitability (Cleary, 2020). Another classical interaction is the direct effect of a carbon price on energy prices, because it is transferred to the variable generation costs of CO_2 emitting technologies.

In hindsight, these mechanisms reintroduce centralized coordination and requirements, as previously implemented by regulators and regulated utilities. These include pushing the development of certain technologies regardless of market signals, and ensuring resource adequacy, which energy markets have not achieved. An alternative could be to switch to a new market design paradigm with two elements: (i) energy markets to deal with short-term coordination, and (ii) long-term contracts for investments issued by a central authority in charge of driving the energy mix through technology-specific and/or technology-neutral tenders. This has been summarized by Roques and Finon (2017) as a competition in two steps: competition *for* the market, and then competition *in* the market. This hybrid model could facilitate investment in line with governments' objectives, but it would rely on a central authority to guide the long-term mix. Introducing a predictable energy mix in future forecasts could also reduce uncertainties around cash flows, and thus reduce the cost of capital for investors by transferring the risk to ratepayers when the central authority's mix trajectory is improperly defined. Finally, the system operator could also handle extreme weather events or climate change issues by considering relevant scenarios and common cause failures when assessing resource adequacy.

Designing Markets Resilient to Climate Change

Looking forward, planning for climate risk and the increasing frequency of extreme weather events will require a fundamental shift in the mindset of regulators. Importantly, without understanding how markets operate, whether energy-only or energy-plus-capacity markets, and what price signals can and cannot do, regulators will fail to cost-effectively implement policies that can secure grids against climate change, and instead blame the markets.

Resolving the quintessential energy economics question of energy-only or energy-plus-capacity markets will not necessarily better prepare us for the threat of climate change. Both types of markets, if properly designed, can ensure resource adequacy during non-extreme events. However, a theoretically 'perfect' market design might not guarantee resource adequacy under the extreme weather events that climate change is likely to bring.

Even with continued market improvements, as suggested above and in Bialek et al. (2021), and eliminating market and regulatory barriers to clean energy resources, whether through incorporating a carbon price or eliminating the MOPR, energy regulation must evolve for markets to be resilient.

First, regulators need to step back to understand the associated market failures, and then implement policies to solve these market failures, not just for the power system but for entire critical infrastructure systems.

Resilience to extreme weather events is a public good distinct from reliability or resource adequacy (Unel and Zevin, 2018), and the Texas experience highlights this difference. ERCOT's Seasonal Assessment of Resource Adequacy report shows sufficient installed capacity for both its demand forecast and all-time winter peak demand (ERCOT, 2020). Its analysis after the blackout event also showed that, had they been able to generate, the installed capacity would have been sufficient to cover the (estimated) peak load (ERCOT, 2021). However, not enough of these generators were sufficiently winterized, despite their potential to earn revenues high enough to cover a significant portion of their entire capital costs in just a few days (Cramton, 2021). In other words, while market revenues have incentivized the installation of sufficient capacity to meet peak demand, they were not sufficient to incentivize weatherization without further intervention.

Second, climate risk brings additional information problems that regulators must address. It is possible that grid actors consider extreme weather risks, but they take little or no action because they underestimate the probability of a significant event affecting them due to insufficient data and analysis, or there are insufficient market incentives to do so. Such underestimation is even more problematic if future analyses are based on historical data, given that climate change is expected to increase the frequency and severity of extreme weather events, or if they do not account for the uncertainty of forecasts of such events (Li, Coit, and Felder, 2016). In the case of such information problems, markets would similarly fail to incentivize a socially efficient level of weatherization.

Third, it is important to understand the interconnected nature of the infrastructure and to holistically assess the systemic vulnerability to extreme weather events.

Even if power markets are designed 'perfectly' with proper scarcity pricing, VOLL, or capacity product definition, the power system will not be reliable or resilient if that design, and other policies including coupling regulation, does not consider common cause failures, the vulnerabilities of the gas system, or the interdependencies between the natural gas and electric systems (Felder, 2001, 2004).

Finally, regulators and policymakers should understand the markets they are regulating and what market incentives can and cannot achieve. Overriding market algorithms to increase prices to incentivize generators to come back online once they are already frozen, the way the Public Utility Commission of Texas did, will not achieve resilience, just a large transfer of surplus from consumers to generators (Jaffe and Felder, 1996). However, coordinated planning and advance action by regulators of different sectors is required, with a combination of market incentives and regulatory requirements. Regulators need to also evaluate how markets can prepare for and respond to future extreme events.

Overall, preparing for a future with more frequent extreme weather events requires a comprehensive vulnerability assessment that covers the power systems and all the critical infrastructure systems, such as pipelines, water, and communications, and their interdependencies. To be informative, this assessment should consider the increasing risk posed by climate change, and hence be forward looking in its assumptions for the changing risk and the changing demand and supply. This requires better information about threats to be available for market participants and regulators. Importantly, designing a reliable and resilient power system requires regulators who understand the power markets and market failures, how electricity markers are embedded in the reliability and resiliency policies for transmission and distribution, who recognize the systemic risk climate change poses, and are willing to take direct regulatory action when certain market failures require it. Market designs should aim not just for reliability and resource adequacy, but also for resilience, with a combination of market-based incentives and mandates for risk assessments.

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Footnotes

[1] The MOPR has been introduced to prevent subsidized technologies being more competitive than non-subsidized ones. It stipulates that new, subsidized resources offer a minimum required price, which is defined by the regulator based on the energy-only missing money (with no consideration of subsidies).

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

TODD AAGAARD AND ANDREW KLEIT[1]

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.

Todd Aagaard is with Villanova University's Charles Widger School of Law. **Andrew Kleit** is with The Pennsylvania State University. Kleit can be reached at ank1@psu.edu

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

[1] Contact author: Andrew Kleit, ank1@psu.edu. This piece is adapted from portions of Chapter 13 of Aagaard and Kleit, *Electricity Capacity Markets* (Cambridge University Press, forthcoming 2021).

[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).

The Texas Power Crisis Seen from the EU: a testbed for its resilience and risk-preparedness rules

BY ANNE HOUTMAN AND MARIANA LIAKOPOULOU

Anne Houtman is the Former Ambassador of the European Union and Member of the Belgian Royal Academy. **Mariana Liakopoulou** is an Energy Security Research Fellow, NATO Association of Canada. Mariana Liakopoulou can be reached at liakopouloumariana@gmail.com

Abstract

The chain of events in the Texas crisis is a testbed for the relevance and more importantly, the effective implementation of the rules the European Union (EU) introduced in recent years on the security of its electricity and gas systems, aiming at improving their resilience and risk-preparedness.

As European energy markets became more integrated, energy security also became a European issue as a disruption of supply in the system of one Member State (MS) can affect other MSs. At the same time, the smooth functioning of the European markets and an adequate level of interconnections between MSs are the first EU priority to guarantee the security of supply. But this is not sufficient and rather stringent EU regulation was put in place - in 2017 for gas[1] and in 2019 for electricity[2] - to safeguard supply in the case of extreme climate events, fuel shortages as well as accidental hazards or malicious attacks. Risk assessments, the elaboration of preventive and emergency plans and their implementation are closely coordinated and monitored at EU level, for both electricity and gas systems. Most importantly, the recent EU regulations introduced solidarity mechanisms whereby MS cooperate and give each other assistance to prevent or manage electricity and gas supply crises. Finally, when developing its crisis scenario of a gas fuel shortage, the European Network of Transmission System Operators for electricity (ENTSO-E) must use the scenario developed by its equivalent for gas (ENTSO-G) and the two entities are cooperating more and more in the context of energy system integration. Information channels, including early warnings, are also well defined, with the European Commission (EC) playing a central role in coordinating emergency response.

The electricity perspective

With electricity as a source of heating for 61% of Texas households[3] and poorly insulated houses, the cold wave that hit the State in February 2021 saw electricity demand peak to 74 GW. While electricity represents only 5.2% of the EU energy consumption for residential heating, this share is bound to increase with the deep decarbonization policy launched by the European Green Deal and the roll-out of heat pumps. As almost 75% of the EU building stock is also considered energy-inefficient, building renovation is among the priorities of the EU decarbonization strategy.

When the cold wave hit the State, available power generating capacities totalled about 77 GW, enough in theory to cover a higher demand that did not surpass Winter peak load forecast. Many commentators were quick to point to Texas' reliance on an « energy-only » market to ensure electricity resource adequacy and even to the growing share of variable renewables as the causes of the blackouts. Yet electricity market design and the absence of capacity markets do not appear to be the prime cause of the electricity shortage, and as neighbouring states were facing similar conditions, a higher interconnection level would probably not have offered much help. What seems more at stake are the lack of preparedness of the gas and electricity systems to climate-related risks and of regulatory oversight, as well as poor coordination and cooperation between the operators and regulators of the interdependent electricity and gas systems.

Market design however did play a role in the consequences suffered by consumers. Wholesale market prices surged from a normal average of $50/MWh to more than $9,000/MWh, and with dynamic pricing contracts, Texas consumers were exposed to this spot price volatility and faced unaffordable bills. Dynamic pricing is a cost-effective way to activate demand response during peak demand periods if consumers are able to easily manage their consumption. Where shortages occur for such a long period during an extreme cold wave it is only practicable with local generation and storage resources. As EU rules now foresee the entitlement to dynamic price contracts for its consumers, the Texas crisis questions whether even mandatory information on the risk of such contracts and the need to have an adequate electricity meter installed are sufficient to protect those customers not equipped with alternative resources, either as prosumers or within energy communities.

In addition, while it is reasonable to have consumers pay a higher price during demand peaks, it is questionable whether they should suffer the consequences of unpreparedness of the system or even negligence of utilities and regulators. Security measures such as the weatherization of installations have a price which would reflect in higher consumer bills but is probably worth paying for. It is likely that the vast majority of customers, in particular households, are not aware of the trade-off: the benefit of marginally higher bills to cover security investments largely outweighs the much higher cost of risk such as the system failure seen in February estimated at more than $195 billion[4]. Resilience has a value whose cost Europeans are paying for. Common EU rules and methodologies apply to all EU critical infrastructures, including energy grids, and to the reliability standards MS must set for example when applying capacity mechanisms. As many parts of the EU are particularly exposed to extreme weather events, the methodology set by ACER for assessing seasonal and short-term adequacy relies, among others, on a state-of-the-art climate data basis.

Governance and transparency matter too. With Texas only marginally interconnected with surrounding systems, ERCOT operates a largely isolated and in-sourced power grid and can escape from the federal oversight of FERC, while the Public Utilities Commission of Texas (PUCT) appears to have done little to obtain adequate information from ERCOT and to push for weatherization. ERCOT could thus simply ignore FERC's recommendations and warnings following similar crises in the past. In contrast adequate flows of information, while ensuring the confidentiality of sensitive one, are an essential part of EU security rules. MSs must each designate a competent authority tasked with the control of the implementation of EU rules on security, including to issue an early warning to the EC as soon as they have reliable evidence of a likely disruption. A common entity for electricity and gas, the Agency for the Cooperation of Energy Regulators (ACER) monitors on an ongoing basis the security of electricity supply measures and must report to the Electricity Coordination Group (ECG), a forum of exchange of information and cooperation between MSs, in particular in the area of security of electricity supply.

The gas perspective

Gas-fired power plants accounted for about half of the capacity that went offline in February. According to ERCOT's ex post analysis, more than 20% of the outages were due to gas supply shortage, themselves largely attributable to electricity shortage. Output from Texas's largely un-winterized and liquids-rich shale plays declined due to freeze-offs at wellheads and frozen pipelines. Electrically-powered compressors facilitating pipeline gas flows – in their turn required for power generation- went offline, as a result of ERCOT's requests towards utilities to urge industrial customers to curtail consumption. This chicken and egg situation between the difficulties of the electricity and gas systems to cope with the extreme temperatures pleads for even closer coordination and cooperation between responsible entities of both systems, which is why EU rules foresee cooperation between them already at the stage of scenarios definition. But gas-fired electricity generation represents only slightly more than 20% of the EU power mix[5], a relatively small but stable share compared to more than half in Texas.

Unlike the in-sourced Texas, the EU-27 has recorded a 2019 dependency rate of nearly 90 percent, as indigenous production has been gradually mitigated, especially following the Groningen gas caps imposed by the Dutch government[6]. Consequently, most gas supply disruptions in Europe have been related to outages or decisions originating in third countries. Notable examples include the priority given by Gazprom to its domestic customers during the February 2012 cold spell, in tandem with accusations towards Ukraine for "excess gas withdrawal"[7] to the outage at Norway's Nyhamma gas plant in 2013, which, in combination with unseasonably low temperatures and a water pump failure in the UK-Belgium Interconnector, led to a surge in the NBP price, and the geopolitically-led Russia-Ukraine gas disputes of the 2000s and mid-2010s[8]. Only in a few instances were disruptions due to domestic events such as the late 2017 blast at Austria's Baumgarten hub coupled with the shutdown of the UK's Forties pipeline system, that sent day-ahead PSV price soaring[9].

EU gas demand is expected to remain relatively stable or only slightly decrease to +/-400 bcm until 2030 depending on economic progress, natural gas price competitiveness versus renewables in the power sector and the market share of renewables and electricity storage by that year[10]. Meanwhile decarbonization will decrease the EU's primary energy import dependency to circa 20%-36%, but imports of competitive natural gas resources outside the EU territory are projected to bear an impact on the future energy supply until 2030[11]. Therefore, EU is poised to remain prone to all four above-mentioned types of disturbances, be they highly predictable (e.g., weather-related), relatively predictable (e.g., due to unplanned outages), impossible to predict (e.g., due to accidents and technical error factors) or partially/purely geopolitical.

To the extent that EU gas system flexibility is mainly driven by an active policy of diversification of pipeline gas and LNG sources, by increasing interconnectivity of national markets complemented by reverse flows, which foster inter-MS price convergence, and by large market-driven storage capacity, it is rather similar in that respect to the well-connected Texas system, also equipped with ample underground storage space. These flexibility factors have each in turn or in combination played a role to ease EU market tightness in the various occurrences of supply disruptions. Price signals have directed market players to alternative sources or increased storage withdrawals, which can be interpreted a sign of a well-functioning single EU gas market[12], while the slight rise in electricity and coal prices during the Baumgarten/Forties disturbance has also demonstrated the ability of the electricity market to arbitrate between different sources[13]. However, it should also be noted that it has proved overall easier for market-based responses to be triggered in times of gas shortfalls particularly in Northwestern Europe, which, compared to Eastern and Southern Europe, has achieved timely market integration via gas-on-gas competition and the lifting of cross-border barriers.

A last issue merits attention in view of the Texas chain of events, that of the priority given to certain customers in case of gas supply disruption. This prioritization in the regulation has been driven by the Treaty-based, risk-sharing perception of energy security as an inter-MS "solidarity" issue[14] due to negative spillovers from distinct national policies[15]. One of the aims of EU rules is to safeguard uninterrupted supply of gas throughout the Union to household gas users and other vulnerable customers who are considered as « protected customers » in the event of difficult climate conditions and this holds true also in case the solidarity mechanism must be activated. However, those rules take an integrated approach of gas and electricity systems whereby priority may be given to gas-fired power plants over protected customers if the lack of gas supply would affect the functioning of the electricity system or hamper the production and/or transportation of gas.

Conclusion

As part of the EU Governance of the Energy Union and Climate Action adopted in 2018[16], the EC already has the tools to monitor progress in MS on adaptation to climate change, in particular in relation to energy security. In line with the Green Deal's vision of a climate-resilient society, the EU has recently decided to further raise its ambition, to widen the scope of its strategy on adaptation to climate change[17] and to develop suitable indicators and a resilience assessment framework. This article has demonstrated that the Texas crisis cannot be solely attributed to the "energy-only" market design, but that it has primarily been the result of the lack of preparedness of the gas and electricity systems to climate-related risks, the lack of an integrated approach of the two systems and of regulatory oversight. And it is for this reason that this crisis reminds us how important it is for the EU to fully implement its policy on climate resilience and existing rules on security of supply.

Footnotes

[1] Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010, OJEU L 280.

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Texas Power Outages Revealed Supply Vulnerabilities[1]

FEREIDOON SIOSHANSI

Abstract

The Texas power shortages of February 2021 were caused by an extremely cold spell in a system that is customarily prepared to handle extreme hot summers but not adequately winterized. Despite attempts by some politicians to blame wind, it was mostly thermal plants that failed.

Fereidoon Sioshansi is President of Menlo Energy Economics and has over 4 decades of experience covering all aspects of the electricity power ector. He can be reached at: fpsioshansi@aol.com

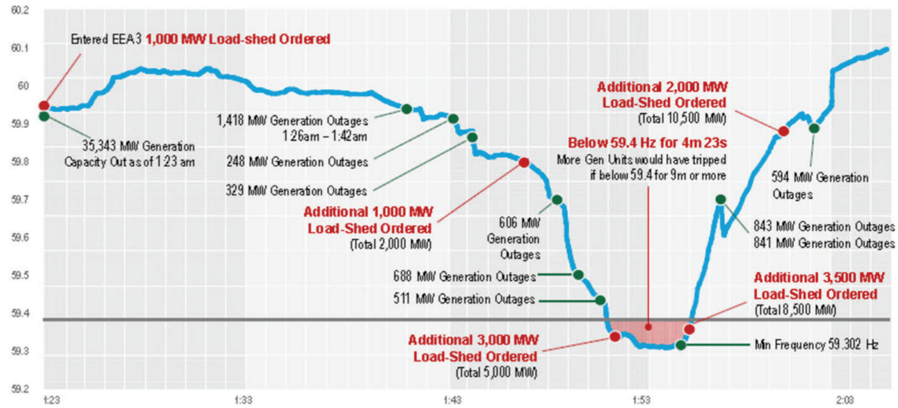
The extensive power supply shortages of mid-February in Texas and neighboring states have been the subject of much heated debate and multiple inquiries including an assessment of the events leading to the long blackouts and high prices that lasted for nearly a week. With power out for so long in so many parts of Texas, water and sewage systems could not function adding to the frustrations of millions of affected citizens left in the cold and dark for days. Once some degree of *normalcy* was restored, the extent of financial damage became apparent with a few customers on real-time price options getting utility bills in thousands of dollars they could not afford and a number of retailers and co-ops declaring bankruptcy.

Not surprisingly, there have been political ramifications for the governor, the **Public Utility Commission of Texas** (PUCT), and the grid operator – which had to explain why there was in fact no "R" in the **Electric Reliability Council of Texas** (ERCOT). There have been on-going debate as the lawmakers debate how best to fix what seems to be a broken system – making sure that there will be adequate supply to serve the load during future extreme weather events.

Among the options to consider there was renewed debate about the wisdom of operating the Texas grid essentially as an electric island – deliberately achieved by politicians who did not wish the Lone Star State to be governed by the bureaucrats at the **Federal Energy Regulatory Commission** (FERC) in Washington, DC. At the height of the crisis, ERCOT could not rely on neighboring states – many of whom were also suffering from power shortage of their own – to cover its shortfall.

As wholesale prices spiked to the maximum allowed $9,000/MWh and stayed there continuously for a good part of 4 days, it became clear that **energy only markets** even with high bid prices do *not* provide sufficient incentives to generators to supply power during an unusual cold spell such as this. While generators missed the opportunity to make a bundle of money – because of equipment failures and/or inadequate gas supplies – there were no penalties for *not* supplying power when it was needed. Everyone wanted to know what kind of market is that – where generators can make heaps of money if they can deliver but suffer no consequences if they don't? Perhaps ERCOT needs some scheme that obliges the generators and/or retailers to supply the forecasted demand – perhaps a **resource adequacy** scheme?

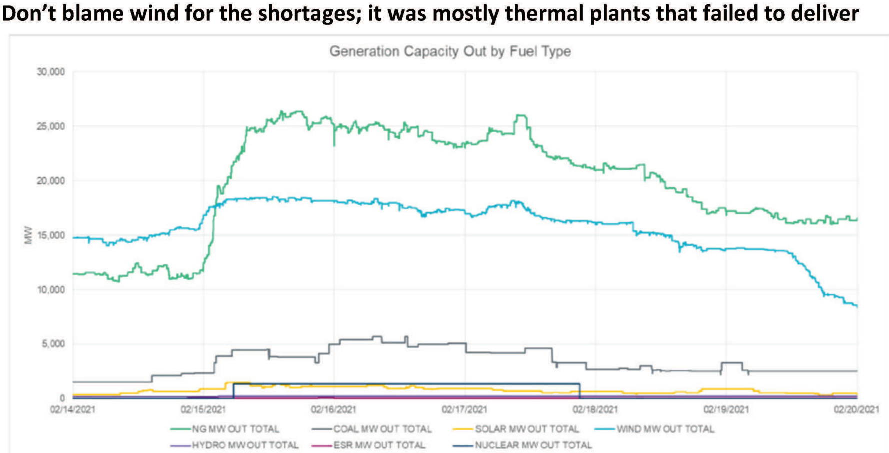
Supplies falling woefully short of demand in midst of freezing temperatures in Texas



Source: Review of Feb 2021 extreme cold weather event – ERCOT presentation, 24 Feb 2021

As it turned out, ERCOT was way off in projecting demand – mostly because such extended cold spells

Don't blame wind for the shortages; it was mostly thermal plants that failed to deliver



Source: Review of Feb 2021 extreme cold weather event – ERCOT presentation, 24 Feb 2021 are unusual in Texas. Everyone, politicians included, learned that when it gets very cold, water freezes, as does everything else that is exposed to the elements – pumps, pipes, valves, wind turbine blades, etc. And if the power to the gas supply system is cut off, no gas or cooling water can get to the power plants to make electricity. And if there is no electricity, the water supply and the sewage systems stop operating, and so on. At the height of the crisis, Texas Senator **Ted Cruz** decided that the best way to address the peoples' suffering was to take a vacation in Cancun, Mexico. That did not go too well once his constituents learned where he was.

While a lot of technical details are being analyzed and debated, the basics boils down to not being adequately prepared for an extended cold spell of the magnitude that engulfed much of the US in mid February. Ma pats of the world routinely manage much colder temperatures for weeks without a hiccup. But Texas, one might say, is much better prepared to handle hot summers – something that happens virtually every summer – than cold winters – something that historically has happened roughly once a decade. With the increased penetration of heat pumps and other types of electrical heating, winter peaks in Texas have risen fast then the summer peaks. In fact in February 2021, the peak demand – had the system been able to meet it – would have probably exceeded 75 GW, in line with historical summer peaks.

In this context, wind turbines in Denmark and Germany continue to operate with temperatures sensors and de-icing equipment. Texas, like many of its neighboring states, *could have* – and in retrospect *should have* – made the necessary investments to *winterize* to avoid the worst of what happened. A prior cold spell in 2011 should have made this clear, but the lessons were not properly implemented.

Following the outages, Texas politicians, regulators and the grid operator have faced the fury of millions left without power and water for days. Among the vexing problems is the grid operator's "inappropriate" pricing that cost the market **$16 billion** over the course of 32 hours, according to **Potomac Economics**, ERCOT's **independent market monitor** (IMM).

During the chaos of the crisis, the wholesale price of power was allowed to hit its $9,000/MWh **market cap** and stay high for 32 hours longer than would have been appropriate (visual). The IMM says ERCOT should have lowered the price immediately after load shed instructions had ended on the evening of Feb 17 rather than allowing them to stay high through the morning of Feb 19.

Subsequently, the IMM has recommended that the PUCT direct ERCOT to "correct" the error to avoid "the inappropriate pricing intervention that occurred" and to prevent "substantial adverse economic effects."

Arthur D'Andrea, who took over as the chair of the commission following the resignation of former chair **DeAnn Walker**, said this would cause more trouble than it solves. He was subsequently fired as was ERCOT's CEO **Bill Magness** who was dismissed by ERCOT's board. In the meantime multiple investigations are taking place to minimize the political and financial damage and move forward before the summer's sizzling temperatures test the reliability of the grid once again.

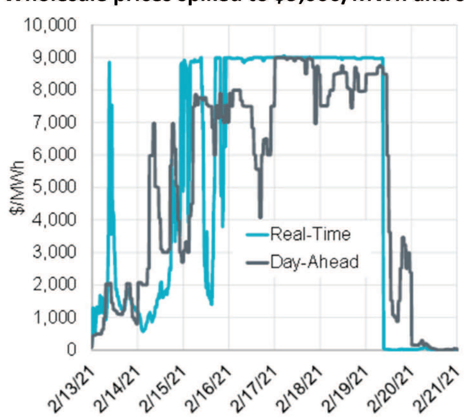
As is usual for any infrastructure investment, it is a matter of balancing the costs versus the benefits. In Texas, the costs of not being adequately prepared have become obvious. Now it is up to the politicians and the regulators to decide if they can afford a repeat of the same either during an extreme summer heat or another unusual cold spell.

Since mid Feb, there has been a flood of articles, opinion pieces, webinars, etc. on the causes of the accident and what can be done to avoid future occurrences including a preliminary report released by ERCOT on 24 Feb and a good summary by the **National Regulatory Research Institute** (NRRI). Most point to the inadequate *winterization* of the entire energy infrastructure, not just the electricity sector but also the critical gas and water supply.

Not surprisingly, some Texas politicians tried to blame the accident on the unreliability of wind and other renewable, pointing to their variability. The evidence clearly suggests that it was mostly, if not entirely, the thermal power plants, both fossil fueled and nuclear, that failed to supply the unusually high heating loads.

Another factor is that as the climate changes, all indications point to more frequent and more extreme weather events. What used to be considered 50-year floods, droughts, hot or cold extremes are now appearing with alarming regularity. During the mid-Aug 2020 rolling blackouts in California, for example, the

Wholesale prices spiked to $9,000/MWh and stayed there for a *very* long time



Average system-wide pricing around the event relative to other historical periods (in $/MWh)

Date Range	Real-Time	Day-Ahead
2/14/21 2/19/21	$6,579.59	$6,612.23
January '21	$20.79	$21.36
February '20	$18.27	$17.74

This data is using the ERCOT Hub Average 345-KV Hub prices

Source: Review of Feb 2021 extreme cold weather event – ERCOT presentation, 24 Feb 2021 temperatures in the state on average were around 10F *above* normal. In mid-Feb in Texas, they were on average around 50F *below* normal. As part of the effort to avoid such devastating shortages in the future, it seems that we have to adjust to new normals.

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and

https://www.utilitydive.com/news/texas-regulators-decline-to-act-after-market-monitor-reports-16b-of-inapp/596252/

Footnotes

[1] An early version of this article appeared in the April 2021 issue of *EEnegy Informer*, available at http://www.eenergyinformer.com

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Vulnerabilities in the Texas Electricity Market: A Comparison of Winter Events in 2021 and 1989

JAY ZARNIKAU

The electric outages in Texas following Valentine's Day of 2021 helped to inspire the theme of this edition of *Forum*. Winter Storm Uri exposed vulnerabilities in the state's electricity markets, resulting in deaths, wealth transfers, and political fallout. It raised questions over the success of efforts to foster competition in the electric generation and retail sectors in the nation's leading state in electricity production and consumption. It renewed debates about the state's considerable degree of independence from other interconnections and limited FERC oversight, as well as the performance of the state's large and powerful natural gas industry. The event attracted media attention and ample "finger pointing." Articles and reports of varying accuracy have been written.

It is instructive to compare the electricity industry's performance during the February deep freeze to an earlier winter event in the days before Christmas of 1989, for a few reasons. First, the weather was similar. The low temperature in Austin was the same in both events. The low in Dallas was just 1°F colder in 2021 than in 1989. Houston reached a low temperature that was 6°F lower in 1989 than in 2021.[1] The weather in 1989 was more-similar to the 2021 event than the relatively-mild winter 2011 curtailment event which is inappropriately used by the ERCOT staff as a severe winter scenario.[2] However, the electricity industry in Texas is far different today, with competition in the generation sector and retail customer choice in many areas of the Electric Reliability of Texas (ERCOT) market. In contrast, the industry was dominated by vertically-integrated electric utilities in 1989 and there was little market-wide control over operations. Texas is now the leader in wind generation in the U.S., though natural gas remains the leading generation fuel. Finally, the comparison is of personal interest to me, since I was the Director of the Electric Division at the Public Utility Commission of Texas (PUCT) back in 1989.

Jay Zarnikau is an Adjunct Professor of Public Affairs at the University of Texas at Austin and senior vice president of Frontier Energy. He can be reached at: jayzarnikau@gmail.com

What happened in February 2021?

In Texas, around 60% of homes are heated using electric space heating, so electrical demand spiked as winter storm Uri moved into Texas and neighboring states in mid-February. Had there not been electrical curtailments, electricity demand would have easily reached a new peak during the winter storm. All types of generation sources reported problems, as noted in Fig. 1. At one point, nearly one-half of the generation capacity in the market was unavailable to the ERCOT system operator. Frequency dropped to below 59.4 Hz. To prevent a catastrophic shut-down of the grid, distribution utilities were instructed to curtail load. Because the required demand reduction was so great and the cold weather persisted for many days, "rolling blackouts" became persistent multi-day outages of electric service for many Texans. Frigid temperatures and unheated homes led to over 100 deaths.

Generators failed for a variety of reasons. There were frozen sensing lines, frozen water lines, and frozen values. Ice accumulated on wind turbine blades. Coal piles turned into chunks of ice. Snow gathered on solar panels, diminishing their output. Many natural gas power plants were unable to obtain fuel because electricity had been cut-off to the electric compressors used to produce and transport natural gas. Natural gas production declined due to wellhead and equipment

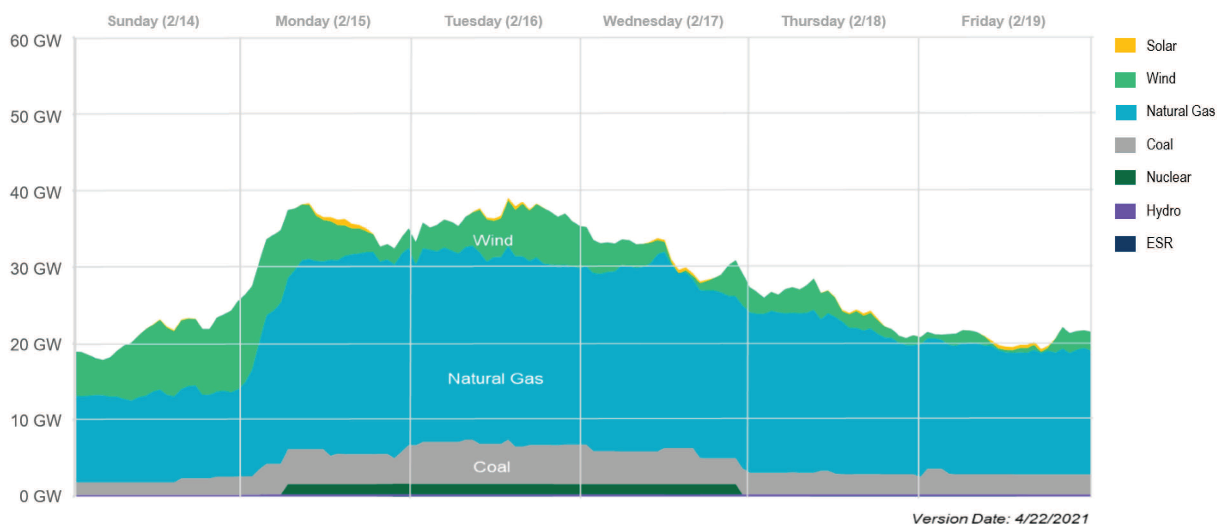

Figure 1. Net Generator Outages and Derates by Fuel Type (Source: ERCOT)

"freeze-offs," as well. Moreover, many peaking units had interruptible natural gas transportation agreements, and providing natural gas service to residential end-use consumers was a higher priority than providing gas to electricity generators since re-instating natural gas service to homes would require labor-intensive physical visits to gas-curtailed homes by the natural gas distribution utilities.

The economic consequences of the event were enormous and unprecedented. Due to a shortage of generation, prices reached the offer cap of $9,000 per MWh during certain periods on February 13th and 14th and were subsequently pegged at that high level from the morning of February 15th to the morning of February 19th in hopes of attracting more generation resources to enter the market and to keep price-sensitive load out of the market. The value of electricity consumed during the week – based on real-time prices and consumption – was roughly $50 billion, or about 5 times the value of electricity consumed during entire years. This value may be misleading, however, given the ample hedging opportunities provided by the market structure.

The ensuing high natural gas prices and high prices of electricity in the wholesale markets for energy and ancillary services operated by ERCOT had large and disparate impacts on market participants. As the centralized counter-party in the markets for energy and ancillary services that it administers, ERCOT reported cumulative aggregate "short payments" or under-collections of approximately $2.9 Billion.[3] ERCOT estimates that it will take 96 years to collect the amounts owed to it by defaulting parties (Brazos Electric Power Cooperative, Rayburn Country Electric Cooperative, and some competitive retailers) from market participants under its existing Default Uplift Invoice process.[4] Among the winners, Kinder Morgan, an owner and operator of natural gas pipelines, terminals and storage, announced a $1 billion windfall profit from gas sales during the storm.[5] Various financial institutions providing financing and hedges to participants in ERCOT's markets also received windfall profits.[6] Among the losers were Brazos Electric Power Cooperative Inc., Rayburn Country Electric Cooperative, and CPS Energy. Retailers Griddy Energy, Entrust Energy, Inc., and Power of Texas Holdings Inc. filed for bankruptcy, as well as Just Energy, which does business under a variety of brand names. Generators who were unable to meet their commitments with their own generating units due to performance problems were among the big losers, having to purchase power in the real-time market at the offer cap to satisfy their commitments to load-serving entities. NRG and Vistra – leaders in both the generation and retail sectors – appear to be among the losers.

What happened in 1989?

Many months before the 1989 winter event, the PUCT Staff warned of reliability concerns associated with ERCOT's high reliance on natural gas for electricity generation:

> Dependence on natural gas in the ERCOT generation mix (almost three times the national dependence) represents some reliability concern. . . . if severe winter conditions were to occur, there could be curtailment of gas supply for generating unites. If such curtailment does occur and it becomes necessary to substitute fuel oil for gas, the rated capability of some units will be reduced due to equipment design, pipeline delivery constraints and/or oil inventories.[7]

Natural gas and oil represented 53% of the generation mix in 1989.[8]

During the winter freeze of December 21-23, 1989, Texas saw record low temperatures, very similar to those experienced in February 2021. Demand for electricity increased, along with the demand for natural gas for space heating. Weather-related equipment problems caused generating units to go offline. Many power plant outages were traced to frozen instruments, frozen valves, boiler tube leaks, frozen batteries, and fish plugging cooling water intakes. Consistent with the concerns expressed by the PUCT staff earlier in the year, natural gas flows were curtailed by Lone Star Gas to the utilities in North Texas in early hours of December 21st, and many utilities serving South Texas lost their natural gas supplies the following morning. This triggered a near loss of the entire ERCOT electric grid.[9] There was firm load shed of 1,710 MW (4.5% of peak load) on December 23rd, 1989, which was far smaller than the magnitude of the outages in 2021. "Rolling" blackouts were achieved. System frequency remained above 59.65 Hz throughout the event.

Differences

Both winter storms resulted in rolling blackouts. During both events, weather-related problems forced outages and de-ratings at power plants and the availability of natural gas to gas-fired power plants was a significant problem. But these were otherwise very different events. The extent and duration of the outages was far greater in 2021. No loss of life was linked to the outages in 1989.

The 1989 event was an inconvenience. The February 2021 event was a disaster.

What accounts for the differences between these two events? Some of the difference is no-doubt related to changes in the physical characteristics of the system over the past 32 years. In 1989, much of the fleet of natural gas generators had dual-fuel capability and switched to fuel oil when natural gas supplies were curtailed.[10] This resulted in de-ratings of 1.5 GW,[11] but kept many plants on-line. There is less dual-fuel capability today. ERCOT's (summer) planning reserve margin was over 20% in 1989,[12] in contrast to the 15.5% reserve margin projected for the summer of 2021.[13] Thus, there was a greater "cushion" of capacity to work with.

Having more market players and less vertical-integration can certainly increase the coordination necessary to preserve reliability. In 1989, there were far fewer participants in the industry.

In 1989, operations were handled by ten local control centers, rather than a single independent system operator. Quality and reliability standards were applied to all investor-owned utilities under the PUCT's regulatory oversight.

There was no large "wealth transfer" from the electric industry to the natural gas and financial services industries in 1989, unlike the 2021 event. Natural gas prices remained fairly stable in December 1989, while prices spiked in February 2021 with dire consequences for end-use consumers and gas-fired power plant owners exposed to those prices.[14] The December 1989 event preceded the establishment of formal wholesale markets for electricity in the ERCOT power region and the PUCT was able to review the costs incurred by the utilities under its jurisdiction and approve recovery of those costs determined to be reasonable and necessary and prudently-incurred.

Responsibility for meeting targeted planning reserve levels was assigned to various utilities in 1989. Today, markets are relied upon to provide sufficient profit opportunities to attract existing resources into the real-time market and foster long-term investment in the generation sector.

In Conclusion

The December 1989 and February 2021 firm load shed events in ERCOT had similar causes. Temperatures were similar. The explanations for generation outages and deratings were similar. The interdependence of the electric and natural gas industries was highlighted each time. The types of recommendations that were made by the PUCT staff and the North American Electric Reliability Corporation (NERC) following the outages in 1989 and 2011 for better winterization of the generation and transmission infrastructure and better coordination with the natural gas industry[15] will probably again be repeated.

But the industry structure is far different today than it was in 1989. Texas now has competitive markets for electricity, with many market participants in the generation and retail sectors. Markets are relied-upon to balance supply and demand in the short-run and long-run, and prices are permitted to reach higher levels than in most other restructured markets for electricity. Simply tracing who was financially-impacted by the 2021 event is very difficult, due to the presence of hedging arrangements, global markets for energy, and many proprietary arrangements among market participants. The economic impacts of this type of event on consumers and market participants have become enormous and better-mitigating some of those impacts is now a focus of attention.

Footnotes

[1] It is noteworthy that the winter storms during December 1989 and February 2021 are not without precedent in Texas. See James Doss-Gollin, David Farnham, Upmanu Lall, Vijay Modi (2021). How unprecedented was the February 2021 Texas cold snap? Accepted for publication in *Environmental Research Letters.*

[2] See, for the example, the Scenario tab in: http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.xlsx.

[3] Electric Reliability Council of Texas Inc.'s Notice of Planned Implementation of Default Uplift Invoice Process, PUCT Project No. 51812: Issues Related to the State of Disaster for the February 2021 Winter Weather Event.

[4] Electric Reliability Council of Texas Inc.'s Notice of Planned Implementation of Default Uplift Invoice Process, PUCT Project No. 51812: Issues Related to the State of Disaster for the February 2021 Winter Weather Event.

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

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

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[11] https://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/ERCOT%20Emergency%20Operation%201989.pdf

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[14] https://www.eia.gov/dnav/ng/hist/n3050tx3m.htm

[15] FERC and NERC, Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations. August 2011.

The Catastrophic Texas Blackouts: Lessons For The Developing Countries

BY DR. TILAK K. DOSHI

Dr. Tilak K. Doshi is a Senior Visiting Research Fellow with the Middle East Institute, National University of Singapore. He analyzes energy economics and related public policy issues. He can be reached at: meitkd@nus.edu.sg

The recent severe snowstorm in the US led to a catastrophic power outage in Texas leaving millions of people without access to power or heat for several days, with a mounting death toll that has yet to be fully tallied.[1] The state was about 4 minutes and seconds away from a total grid collapse[2] that would have left the state's residents for weeks or months without power. If that were to have happened, tens of thousands of people would have been at the risk of freezing to death.

Political leaders in Asia, Africa and Latin America, well aware that reliable and affordable electricity for their burgeoning middle classes is a pre-requisite of staying in office, would no doubt incredulously ask "How could this happen in Texas, the energy power-house of the US, the country which surpassed Russia in 2011 to become the world's largest producer of natural gas and overtook Saudi Arabia in 2018 to become the world's largest producer of oil?"[3]

Energy planners and grid engineers in many developing countries work with creaky grid infrastructure and frequent breakdowns lead many of their customers to own diesel gen-sets as ready backups. The irony will not be lost: last week, President Biden ordered the federal government to provide diesel generators and diesel fuel along with other assistance to Texas amid the power outages brought on by extreme cold.[4]

Policy Lessons Of The Texas Debacle

For energy policy makers around the world, the lessons of the Texas debacle will be a warning sign in their own planning for power grid reliability and resilience to adverse events. Thus, UK's *The Telegraph* ran a headline: "Blackouts in energy-rich Texas are a wake-up call for knife-edge Britain".[5] However, gleaning policy lessons will not be straight-forward.

Like most controversies in America these days, the failures of the Texas power grid when it was most needed led to a blizzard of blame and finger-pointing largely along partisan lines. A torrent of information, analysis and "fact checks" has occupied the media and its talking heads as the extent of the grid failure became apparent.

For those convinced of an impending climate Armageddon (usually one or two decades away) such as Congresswoman Alexandria Ocasio-Cortez, a simple tweet says it all: "The infrastructure failures in Texas are quite literally what happens when you *don't* pursue a Green New Deal."[6] Fellow travellers on the "climate crisis" bandwagon deny that the icing-up of wind turbines --captured in a classic meme of an oil-fuelled helicopter spraying oil-derived anti-freeze on turbines made with oil-based products -- played a role in the grid failure.[7] They accuse "fossil fuel interests and their allies in the Republican Party" of hiding the "real culprit": natural gas and power grid "poorly prepared to deal with severe winter conditions after years of deregulation".[8]

In the polarized world of American politics, the 'other side' is personified by the likes of the Texas Public Policy Foundation, described by Wikipedia – the "go-to fact-checker" for many – as "a conservative think tank with ties to the fossil fuel industry".[9] TPPF alleges that the storm "never would have been an issue had our grid not been so deeply penetrated by renewable energy sources."[10]

Who Is Right?

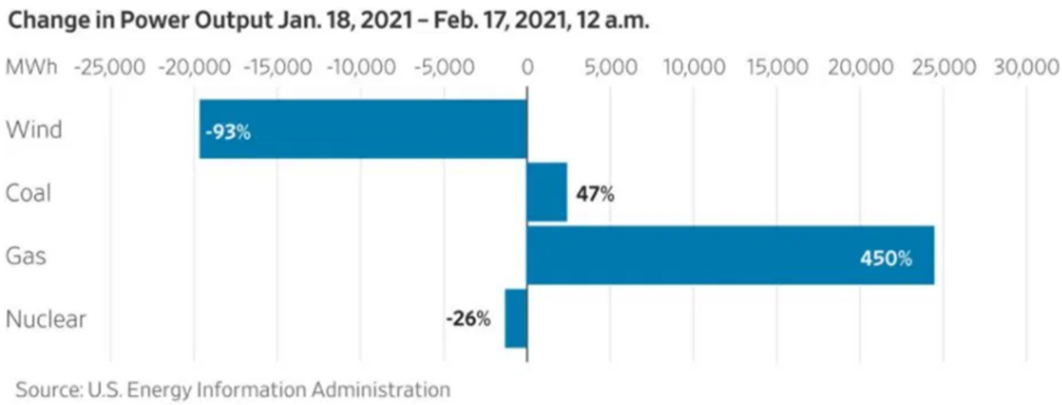
Is the TPPF view right? This is a hugely important question. The lives and basic comfort of many people are at stake. The fate of many a planner or politician around the world depends quite literally on getting on the right side of the debate over the Texas debacle. For developing countries, the stakes are far higher as the lower per capita incomes of their constituents carry risks that few in the rich world can appreciate.

One might think that the truth of the Texas blackouts is far more prosaic. It was simply the extreme weather. The fact is that all energy sources – coal, natural gas and nuclear as well as wind -- were not "winterized" due to short sighted, profit-focused planning in a deregulated market, as the *Texas Tribune* would have it.[11]

Alas if that were but true. For those whose professional work is in the engineering, economics and public policy aspects of power grids, the Texas debacle has been decades in the making. To begin with, fossil-fuelled power plants are designed for cold weather and rarely freeze. Fossil-fuelled power plans run in severe cold weather conditions around the world, from the Arctic steppes of Siberia to the northern reaches of China and India, not to mention the frigid plains of Canada.

Decades of policy preferences in Texas in favour of weather-dependent, intermittent "renewable energy" – read solar and wind – added 20 GW of capacity since 2015 while retiring coal power plants and barely adding to natural gas capacity.[12] More than $80 billion in Federal subsidies were spent on wind and solar during 2010 – 2019; an additional average of $1.5 billion is spent annually on state subsidies for renewable energy. A deregulated market that rewards power generation without requiring reliable capacity ready to supply power as needed naturally tilted the field in favour of intermittent solar and wind power.

The standard response of the renewables lobby is that fossil fuels receive subsidies too. The fact that wind receives 17 times, and solar an astonishing 75 times, the fiscal support that fossil-fuelled power generation receives on a per kilowatt-hour basis[13] is lost in the rage of the culture wars between the renewable energy advocates and their counterparts on the side of oil, gas and coal.



Texas thus opted to lose reliable generation capacity while counting on solar and wind to keep up with power demand. To any engineer worthy of his degree, the increasing likelihood that an event that combined very high demand with intermittent wind and solar power output would lead to blackouts would be apparent. As one observer, a former Republican member of the Texas House of Representatives puts it, "the only surprise was that such a situation occurred during a rare winter freeze and not during the predictable Texas summer heat waves".[14] The knife-edge fragility of power grids in Western Europe[15] and the UK[16] which have imposed policies that forced rapid growth in renewable energy capacity is no surprise.

Perhaps the most straightforward view of what transpired is given by the chart below. It shows the change in power output by fuel in Texas between January 18th and February 17th. Not only did coal and gas power hold up better than wind, which fell by over 90%, but gas turbine generators increased output by a massive 450%, nearly making up for the shortfall in wind. But this proved to be not enough to cover surging power demand brought on by the Arctic blast. It takes chutzpah to assert that because gas, coal and nuclear power did not operate at 100% of expected potential, they "failed" even though wind failed by nearly 100%. [17]

A Most Consequential Irony

For planners and politicians of the developing countries, most of which are signatories to the (non-binding) Paris Agreement, hectored constantly about the need to "transition" from fossil fuels, the Texas debacle provides ironic education beyond just the rushed dependence on diesel generators when the chips are down in one of the world's richest countries.

Perhaps the most profound irony, and the most consequential, should be saved for last. Among the first actions by Joe Biden, the first US "climate president",[18] was to re-join the Paris Agreement. His international climate czar John Kerry met with UN Secretary-General Antonio Guterres to mark America's re-entry barely days after the worst of the Texas tragedy. Convinced that the Earth has 9 years to avert the worst consequences of the "climate crisis" and "there's no faking it on this one",[19] Mr. Kerry called on the world's big emitting countries, including China, India, and Russia to "really step up", cut fossil fuel use and "raise their ambition" to "fight against climate change".[20] The irony however is lost on Mr. Kerry. He goes around lecturing poorer countries on the need for raised ambitions to fight climate change when it is those very same ambitions that led to the tragic debacle in Texas.

Footnotes

1 https://www.wsj.com/articles/full-death-toll-from-texas-storm-could-take-months-to-determine-11614107708

2 https://nypost.com/2021/02/25/texas-power-grid-was-minutes-away-from-total-collapse/

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12 https://gov.texas.gov/uploads/files/business/renewableenergy-report.pdf

13 https://lifepowered.org/wp-content/uploads/2020/07/2020-04-RR-Bennett-LP-Federal-Energy-Subsidies-2.pdf

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Vulnerability in the utility industry: perspective, experiences and lessons from the European Union[1]

BY FRANCESCO CARERI, CATALIN FELIX COVRIG AND TILEMAHOS EFTHIMIADIS

Francesco Careri, Catalin Felix Covrig and **Tilemahos Efthimiadis** are officials of the European Commission - Joint Research Centre, and their research focuses on energy security of supply, infrastructure, and markets. Tilemahos Efthimiadis can be contacted at tilemahos.efthimiadis@ec.europa.eu

Abstract

The European Union is taking initiatives to increase its security of supply, reduce operational vulnerabilities and respond to the threats. This article presents examples, with a focus on the Risk Preparedness Regulation, and the Baltic synchronization plan.

European Union energy crises

The extreme cold spell that hit the southern part of the United States and northern Mexico in February 2021 resulted in disruptions of gas supplies, massive electricity blackouts and interruptions, and destructions of water systems especially in the State of Texas. The events provided a sharp reminder of the vulnerabilities of our infrastructures, especially to extreme events.

The European Union (EU) is no stranger to major incidents on its security of energy supply. Prominent examples are the Russia – Ukraine gas disputes which on occasion led to disruptions of Europe's gas supply: one of the most significant disruptions occurred on January 2009, when Russian gas flows to the Ukraine and the EU were stopped after a trade dispute between Gazprom and the Ukrainian company Naftogaz, depriving EU Member States of 20% of their gas supplies in coincidence with a cold spell in many parts of Europe.[2] Another major gas incident occurred in 2017, when an explosion at a major European gas hub in Baumgarten, Austria, caused several neighbouring countries issuing early warnings or declared a state of energy emergency.

Regarding electricity, most of the transmission grids in Continental Europe are electrically connected to operate synchronously at the nominal frequency of 50 Hz (see Figure 1). On 8 January 2021, the Continental Europe synchronous area was separated into two regions (see Figure 2). According to the interim report on the event elaborated by the European Network of Transmission System Operators for Electricity (ENTSO-E, 2021), the separation event was triggered by a disconnection in the Ernestinovo substation in Croatia (by overcurrent protection) at 14:04 CET. This led to outages of several transmission network elements in a very short time, resulting in the separation of the Continental Europe synchronous area in two synchronous areas: a North-West one with a surplus of load (frequency decreased) and a South-East area with a surplus of generation (frequency increased). The event caused the activation of several automatic and manual countermeasures aimed to stabilize and speed-up the resynchronisation of the system. These included the activation of system protection schemes, activation of reserves, activation of interruptible services in France and Italy, disconnection of non-conforming generation, loads and network elements and countertrading measures. While the resynchronisation of the system occurred about an hour later at 15:07 CET, nevertheless, the incident

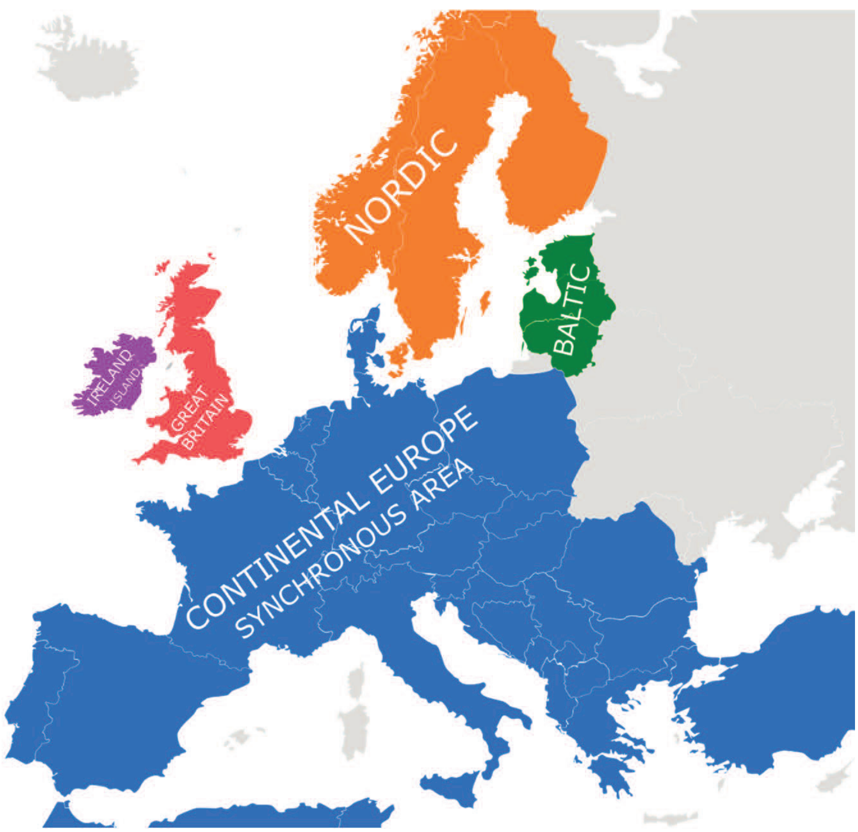

Figure 1. Synchronous power grids of Europe - the Baltic power system is part of the larger BRELL (Belarus, Russia, Estonia, Latvia and Lithuania) power grid. Source: JRC elaboration of ENTSO-E data.

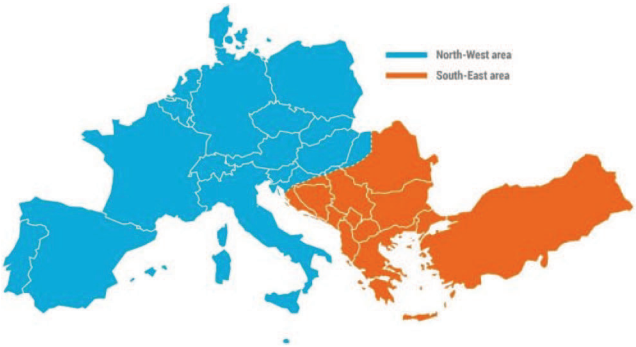

Figure 2. Separation event of 8 January 2021. Source: ENTSO-E (https://bit.ly/3g2BaOb)

resulted in discomfort for several European customers such as localised blackouts in some regions such as North-West Romania.

During the same period of the cold spell in North America (February 2021), a comparable incident occurred in Athens, Greece (and its suburbs), where extreme snowfall caused around 1500 trees, and heavy branches, to collapse on power lines resulting in weeklong blackouts and problems in water systems (frozen pipes that broke etc.). While originally the blame was solely put on the unusual high quantity of snow and the overlapping responsibilities for the clearing of trees around and above the lines, ex-post the National Observatory of Athens published an analysis where they argue that Athens experienced 'wet snow', a rare phenomenon for the area which usually experiences 'dry snow' (Meteo, 2021). Wet snow is about seven times heavier than dry snow (30 kg/m^2 versus 4 kg/m^2) and about four times heavier than normal snow (about 12 kg/m^2). Thus, the heavy snowfall of heavy snow led to the collapse of hundreds of trees catching the authorities by surprise.

In what follows, we provide some examples of how the EU is responding to the various threats and a more in-depth analysis of the Risk Preparedness Regulation, and the situation in the Baltics.

European Union initiatives

The EU aims to be climate neutral by 2050, as part of its obligations stemming from the Paris Agreement. To achieve this ambitious goal, the European Commission (hereafter, the 'Commission') launched in December 2019 the European Green Deal, a comprehensive policy package which also outlines investments needed and financing tools available and explains how to ensure a just and inclusive transition.[3]

This plan will rely on a steady increase of renewable energy sources (RES) and with the participation of various actors in the Internal Energy Market: decentralised markets with more players, better interconnected systems, etc. In this context, uncertainties and **vulnerabilities can potentially increase,** especially given the adoption of innovative technologies, changes in electricity demand, (hybrid) threats, etc.

To mitigate such risks, decrease the impact of events and for increasing resilience, several legislative, regulatory and policy initiatives have been taken at the EU level and more are to follow. Examples include the System Operation Guideline,[4] the Trans-European Networks for Energy (TEN-E) policy focused on linking the energy infrastructure of EU countries,[5] the measures to safeguard the security of gas supply,[6] the recent proposal from the Commission for a Directive on the Resilience of Critical Entities which would consider a variety of systems (energy, transport, water etc.), facilitate the coordination of responses and the calculation of cross-border and cross-sector risks,[7] and other tools. All policies are in coordination with the national plans and actors, while highly specialised European stakeholders and agencies facilitate their drafting and implementation. These include the ENTSO-E and ENTSOG (gas) established in 2008 and 2009 respectively, the (decentralised) EU Agency for the Cooperation of Energy Regulators (ACER) established in 2011, the European Climate, Infrastructure and Environment Executive Agency (CINEA), and others.

While measures are being constantly adopted to avoid risks, for several years the EU has also been promoting **increasing resilience,** which the Commission originally defined as *"the ability of an individual, a household, a community, a country or a region to withstand, adapt and quickly recover from stresses and shocks"*.[8] In effect, as not all events are avoidable, one must be ready to bounce back as quickly as possible. This policy of building-up resilience is being promoted across all sectors: energy, finance, transport etc. To this end, one EU initiative is the Recovery and Resilience Facility which just entered into force (February 2021), and will make €672.5 billion in loans and grants available to support reforms and investments undertaken by Member States, according to their national plans.[9] Each national plan will have to include a minimum of 37% of expenditure for climate investments and reforms. Furthermore, the Joint Research Centre, the Commission's in-house science and knowledge service, conducts several research activities concerning resilience[10] and foresight[11], among other activities.

When dealing with risks of any kind, complacency is always the silent enemy. One must be vigilant and be ready to challenge not only their planned actions, but also the underlying goals. In the context of this article, we can refer to the **EU's electricity interconnection target,** defined as import capacity over installed generation capacity in an EU Member State. This target was originally set and redefined by Expert Groups (Commission Expert Groups are formal bodies formed of externals, working under strict rules and with transparency). In 2014, the target was set at 10% by 2030, and in the same year increased to 15%. In 2017, the singular target was replaced by a methodology which is based on three indicators: a. Price differential between EU countries, with an aim to reduce it below 2 EUR/MWh; b. Ratio between nominal transmission capacity and installed RES capacity, with a target of past 30%; and c. Ratio between nominal transmission capacity and peak load, with a target of past 30%.

In the remainder, we present two examples of EU initiatives to mitigate operational risks, among other goals, which are the Risk Preparedness Regulation, and the Baltic synchronisation project.

EU experiences/responses

EU risk-preparedness

Although efficient electricity markets and well interconnected power systems are key to ensure security of electricity supply, a residual risk of an electricity crisis stemming from natural disasters, extreme weather conditions, fuel shortages or malicious attacks cannot be eliminated. Additionally, the effect of such threats could immediately affect a wide region or, in case they start locally, rapidly spread across national borders. In this context, Regulation (EU) 2019/941 on risk-preparedness in the electricity sector[12] (hereafter 'Risk-preparedness Regulation') part of the wider Clean energy for all Europeans package[13] sets a common framework of rules on how to prevent, prepare for and manage electricity crises in the EU, setting up standards for cooperation among EU Member States (bilaterally or at regional level) under the principle of solidarity of the EU.

The areas of action of the Risk-preparedness Regulation, currently under implementation, are:

a. Common risk assessment methodology: EU Member States shall use common methodological frameworks for the identification of regional and national electricity crisis scenarios, and of short-term and seasonal adequacy issues.

b. Risk-preparedness plans with regional cooperation: Based on regional and national electricity crisis scenarios, Member States shall prepare public risk-preparedness plans under common rules and including national, regional and bilateral measures.

c. Crisis management rules: A crisis should be addressed taking into consideration of cross-border cooperation and assistance and by using market measures first, with non-market measures foreseen as last resort only.

d. Information sharing and transparency: In case of an electricity crisis in course or an issue of an early warning, Member States shall provide explanation about the reasons of the crisis, describe measures taken to prevent or mitigate it and detail needs of any assistance from other Member States.

e. Enhanced monitoring at EU level: Member States shall perform ex-post evaluations of electricity crises and security of electricity supply must be systematically monitored by ACER on a regularly basis.

The Baltic synchronisation project

In the aftermath of the February 2021 crisis in North America, a recurring question is whether Texas would have experienced fewer issues if it were better connected with the rest of the US grid, instead of being an 'electricity island'. Practitioners may recall that this issue was also considered after the 2011 cold spell which affected the same region but with fewer consequences.

Alike the US, Europe also has its own 'electricity island' of sorts, which are the electricity grids of Estonia, Latvia and Lithuania (hereafter 'Baltic States'), former Soviet Republics and now EU Member States, are still part of the BRELL common synchronous area together with Belarus and Russia (see Figure 1). The fact that the Baltic States are dependent on one external operator for the operation and balancing of their electricity network has been recognised as an energy security of supply concern by various actors including the Commission.[14]

In 2007, the political desire for the region to join the European synchronous area was formally declared by a Baltic Prime Ministers' decision. In addition, for Estonia, our own research found a high societal appreciation for security of energy supply (Longo et al., 2018), and a staunch support (high willingness-to-pay) for long-term security of supply policies (Giaccaria et al., 2018).[15]

In June 2019, the 'Political Roadmap on implementing synchronisation of the Baltic States' electricity networks with the Continental European Network via Poland' was signed by the Commission and the Republics of Lithuania, Estonia, Poland and Latvia.[16] The synchronisation of the Baltic States' grid with the continental European network is foreseen to be completed in 2025.

Already, recently established electricity lines with Poland (LitPol Link), Sweden (NordBalt) and Finland (Estlink 1 and Estlink 2) have connected the Baltic States region with European partners. However, the electricity grid is still in a synchronous mode with the Russian and Belarusian systems.

From a technical perspective, the synchronisation plan and the Baltic energy market interconnection plan (BEMIP)[17] in general, consist of many projects, many relevant for internal grid reinforcements. These include new AC lines, synchronous compensators, voltage stabiliser units etc. Among others, these additions are expected improve transient and frequency stability in Baltic States (Purvins et al., 2016).

One of the major infrastructure projects for the plan's implementation will be the (new) **700 MW HVDC 'Harmony Link',** a 330 km (205 mile) undersea cabling system that will connect Lithuania with Poland. This interconnector will increase system adequacy in Baltic States, mitigate risk of power failures, will have black start capabilities, enable the integration of further renewable energy capacities, and reduce price differentials between Baltic States and EU as traders and producers of electric power will be able to sell electric power everywhere in Continental Europe (L'Abbate et al., 2015).

The interconnector was approved (final investment decision) in early June 2021 by the transmission system operators of Lithuania and Poland and will be the second one between the countries. The first is the above mentioned LitPol Link, a 341 km (212 mile) overhead line with a current rating of 500 MW which is planned to be doubled in the coming years (see Figure 3).

One of the past deterrents for the implementation of the Baltic synchronisation project may have been the associated costs which are estimated at EUR 1.6 billion (about USD 1.94 billion), potentially a tall order for the three countries with a combined population of about 6 million (or one-fifth of Texas). However, the EU is providing major support and about 1 billion euros have already been given from the EU's Connecting Europe Facility (CEF) to Estonia, Latvia, Lithuania and Poland.[18]

It should be further noted that the synchronisation plan is just one element of BEMIP which aims to achieve an open and integrated regional electricity and gas market between EU countries in the Baltic Sea region. The initiative's members are Denmark, Germany, Estonia, Latvia, Lithuania, Poland, Finland and Sweden, while Norway is an observer.

Figure 3. Baltic power system development plan (new and upgraded power lines). Source: JRC elaboration of ENTSO-E data (TYNDP, Europe's Network Development Plan, Baltic States Synchronization with Continental Europe).

Summary

The recent experiences on both sides of the Atlantic show that, not only do vulnerabilities still exist, but risks are seemingly increasing due to extreme weather events, geopolitical considerations, the introduction of innovative technologies, the transition to a climate-neutral society etc.

In this text, we presented various EU initiatives to address operational vulnerabilities and security of energy supply, and presented the examples of the EU Risk Preparedness Regulation, and the ongoing Baltic synchronisation project. For the latter, we focused only on the technical elements. However, one must acknowledge that there is also an especially important political dimension on the synchronisation plan, as is in Texas, albeit the politics appear to lead to opposite results for the two regions.

Finally, on the Baltic synchronisation project, there's yet another consideration with a technical and political dimension, which concerns Kaliningrad Oblast (or Kaliningrad Region), a semi-exclave of Russia found on the coast of the Baltic Sea, between Lithuania and Poland (Figure 3). With a population of about one million, the region is physically isolated from the rest of Russia but a part of the BRELL synchronous area. The question stays whether the Kaliningrad Oblast will be operating in synchronous mode with Baltic States and EU, or in asynchronous mode. In the latter case, while the region has enough generation to meet its needs, Europe would once again have a distinct energy island, although much smaller than before.

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Footnotes

[1] Disclaimer: The views expressed are purely those of the author and may not in any circumstances be regarded as stating an official position of the European Commission.

[2] SWD/2017/0294 final https://europa.eu/!Gr76vu

[3] European Commission – A European Green Deal https://europa.eu/!Tr74bn

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[8] More broader definitions have also been adopted by the Commission, but for the purposes of this article we'll rely on the definition in the text (for an alternative see the "EU global strategy" https://europa.eu/!yp36QV).

[9] https://europa.eu/!jt78Jr

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[12] Regulation (EU) 2019/941 (p. 1–21) https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0001.01.ENG

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[18] Litgrid https://bit.ly/2RuBsnz

What is the Value of Security of Supply for Households and Business Consumers? An Assessment Accounting for Trade-offs and Psychological Drivers

BY ALESSANDRA MOTZ

Alessandra Motz is a post-doc researcher at the Università della Svizzera italiana, Lugano, Switzerland. She can be reached at alessandra.motz@usi.ch

Abstract

The damage that households and businesses suffer because of a blackout may be influenced by psychological traits, and may as well reflect the perceived trade-offs between security and environmental sustainability of the electricity supply. Two analyses conducted in Switzerland provide an example on the role and impact of these drivers.

The prolonged and unexpected blackout that hit Texas at the beginning of 2021 brought the issue of security of electricity supply back in the spotlight. This topic has indeed become increasingly important in the context of the energy transition, that implies both a deep restructuring of the energy and electricity systems, with growing contributions from intermittent renewables, and the electrification of a larger share of final energy consumptions.

Security of supply and the energy transition: supply-side and demand-side approaches

Over the past decade the measures adopted in several European countries to safeguard the continuity of electricity supply along with the progress in the energy transition have witnessed an interesting shift from a predominantly supply-side approach to an approach increasingly accounting for demand-side factors. In the early 2010s, indeed, several European countries introduced capacity payment mechanisms in order to protect the profitability of the programmable generation plants that were often displaced in the merit order of the wholesale market by the new renewable generation capacity, but were still necessary for security reasons. Over time, however, the distortions induced by these measures on the electricity markets became visible, and several researchers and institutions suggested that wholesale electricity markets should have been cleared from artificial price caps and floors that hindered the formation of effective scarcity signals over the relevant time horizons. Wholesale electricity markets should instead have been designed taking into account the value that consumers actually place on security. This kind of reasoning gradually informed the European legislation for the energy markets: Regulation (EU) 2019/943, for example, states that the maximum and minimum clearing prices adopted for technical reasons on the wholesale electricity markets should be determined taking into account "the maximum electricity price that customers are willing to pay to avoid an outage", i.e. the so-called Value Of Lost Load (VOLL). According to the same Regulation, the VOLL should also be used for assessing the reliability standard desired in each country, and thus for evaluating the real need for capacity payment mechanisms; the VOLL should moreover be computed based on a transparent and coordinated methodology.

What is then the value of security? And what are its determinants?

The growing importance of a demand-side approach leads us to the crucial question: what is then the value that consumers place on security? What are the drivers that may affect this value? And what are the preferences of consumers toward the alternative options to ensure security?

Most of the existing analyses concerning the value of security rely either on macroeconomic data, or on survey data. Macroeconomic data are used to compute the VOLL as a ratio between the contribution of each consumption segment to the gross domestic product on the one hand, and the electricity consumption of the same segment on the other hand. Survey data are instead used for detailed and customized assessments of the magnitude and kind of damage that a blackout with different characteristics may cause to specific consumption segments. The uniform VOLL methodology adopted in the European Union pursuant to Regulation (EU) 2019/943 is mostly based on survey data complemented with information on electricity consumption profiles, and allows the exploitation of a triangulation of methods to better evaluate the consequences of blackouts for different consumption segments. The main problems observed in the existing analyses lie in the extreme variability of the estimates across countries, consumption segments, and economic sectors, as well as in the low comparability of several studies based on survey data. When considering the possible drivers of the value of security, the evidence provided in the literature converges in suggesting that longer and more frequent blackouts harm more, whereas the availability of advance blackout notice helps reducing blackout damage. Next to these intuitive results, however, these is a series of conflicting findings as regards the role of the typical demographic determinants.

Two studies on the residential and business segments provide interesting hints on the role of psychological drivers

Two analyses we conducted by between 2015 and 2019 in Switzerland may help understanding what lies behind these scattered estimates and, most importantly, what may drive consumer preferences with respect to security. The two studies are particularly interesting as they investigate the perceptions and preferences of households and business consumers toward the security of electricity supply with a focus on behavioural, attitudinal, and cognitive drivers, that are often neglected in analyses based on macroeconomic data or exploiting less detailed information concerning individual behaviour. Both studies exploit original survey data and state-of-the-art econometric techniques from the field of discrete choice modelling, a tool that is already widely used in environmental, transport, and energy economics.

Swiss households and the risk of blackouts: three consumption segments with different attitudes toward security and environmental sustainability

The first study focussed on the residential segment and was developed based on an original survey distributed in January and February 2019 on a sample of 1006 households, representative of the Swiss population. Next to the questions concerning the typical demographic variables, the survey investigated the respondents' energy consumption habits, as well as the respondents' attitudes toward environmental issues and specific primary energy sources available for electricity generation in Switzerland. Finally, the survey also included a "discrete choice experiment", i.e. a series of questions where the respondents were was asked to choose one out of five alternative electricity supply options for their own household, differing in terms of origin of the electricity, price in CHF/kWh, and probability of incurring in a short (5 minutes) or long (4 hours) blackout over the upcoming year. Discrete choice experiments allow the researcher to measure the importance that the respondents place on each of the characteristics of the available alternatives, compute the perceived trade-offs across characteristics, and assess whether the observed preferences vary depending on specific characteristics of individual respondents. Within our setting, the comparison between the perceived impact of an additional blackout and the perceived impact of a higher electricity price allowed us to compute the marginal Willingness To Accept (WTA) for blackouts, i.e. the discount an average household would require in order to accept a higher blackout frequency. We found that the WTA for blackouts varies substantially both depending on the primary energy source used for generation, and depending on the attitudes and energy consumption behaviour of individual respondents.

More in detail, we identified within our sample three consumption segments, so-called "latent classes", showing different attitudes toward both the risk of blackouts, and the evolution of the Swiss electricity system. Table 1 below collects our estimates for the WTA of each consumption segment: the values are expressed in centCHF/kWh, and can be compared to an average final price of electricity for the residential segment around 21 centCHF/kWh over the previous months.

The first consumptions segment, identified as Class Alpha, comprises around 47% of the sample and expresses a relatively low and stable WTA for blackouts, and a mild dislike for blackouts associated to renewable-based generation. Our estimates suggest that the respondents belonging to this group are more likely to be men, with a low awareness about their own energy consumption pattern, slightly older, and worried about the economic impact of blackout on households. The second segment, Class Beta, comprising again around 47% of the sample, shows a very low aversion to short blackouts from renewable-based supplies, a stronger aversion to long blackouts from the same sources, and a very high aversion to short and long blackouts from nuclear-based supplies,

Table 1 – Estimated Willingness To Accept (WTA) values for short and long blackouts from selected primary energy sources

Class Alpha, WTA in cent CHF/kWh		Class Beta, WTA in cent CHF/kWh		Class Gamma, WTA in cent CHF/kWh	
Short blackouts		Short blackouts		Short blackouts	
Hydro	3.49***	Hydro	0.98*	Hydro	20.6**
Mix	-1.52***	Mix	6.01***	Mix	8.24***
Nuclear	0.62	Nuclear	26.12***	Nuclear	97.59***
Sun	8.03***	Sun	0.84*	Sun	-9.87***
Wind	5.45***	Wind	1.71***	Wind	7.21**
Long blackouts		Long blackouts		Long blackouts	
Hydro	5.92***	Hydro	11.78***	Hydro	46.13***
Mix	1.93***	Mix	10.42***	Mix	7.47***
Nuclear	2.15***	Nuclear	117.98***	Nuclear	254.3***
Sun	9.08***	Sun	12.16***	Sun	-7.06***
Wind	6.55***	Wind	7.12***	Wind	34.98***

* p-value ≤ 0.1, ** p-value ≤ 0.05, *** p-value ≤ 0.01. Confidence intervals computed via Delta method.

with WTA values reaching, in turn, 124% and 561% of current electricity prices. Our estimates suggest the respondents belonging to Class Beta are more likely to be men, of slightly younger age, with a low awareness of their own energy consumption patterns, worried about the risk of nuclear accidents in Switzerland, and strongly in favour of the nuclear phase-out envisaged in the Swiss long-term energy strategy. The third and last consumption segment, Class Gamma, shows a very mild aversion to short and long blackouts from sun- and wind-based supplies, and an extreme dislike for short and long blackouts stemming from a nuclear supply, with WTA values for blackouts in the nuclear option skyrocketing to 464% and 1210% of current electricity prices depending on blackout length. The comparison with the Alpha and Beta segments suggests that Class Gamma, collecting around 6% of the sample, is more likely to be made up of women with a high energy literacy.

While the assessment of the WTA values obtained in this study is specific to the Swiss case, our findings suggests that, generally speaking, household electricity consumers may well perceive strong trade-offs between the reliability and the environmental sustainability of the national electricity supplies. Depending on their stance toward specific primary energy sources or, more generally, toward change in the electricity system, they might indeed be ready to trade a slightly lower security level for a slightly greener supply, or for a larger reliance on technologies that are perceived as less dangerous, or finally for the safeguarding of traditional generation technologies such as, in the Swiss case, hydroelectric plants and nuclear generation. Attitudinal drivers such as risk aversion or environmental sensitivity may indeed play a large role in shaping class membership and hence the preferences with respect to blackouts: all in all, these psychological traits may contribute to a substantial share of the variability observed in in individual responses.

The business segment: heterogeneous responses due to different tastes and different decision-making strategies

The second study analysed instead the reactions of business consumers, and was conducted through an original survey distributed between December 2018 and January 2019 on a sample of 543 firms representative of the economy of Canton Ticino, one of the Italian-speaking regions of Switzerland. Next to some questions regarding the size of each firm, its activity, its electricity consumption profile, the availability of back-up devices, and the subscription of an insurance covering blackout damage, the survey investigated the magnitude and kind of damage that a blackout lasting one hour might cause to each firm. The survey also included a discrete choice experiment in which each respondent was asked to choose one out of two blackout scenarios, differing in terms of blackout duration (from 0 to 12 hours), availability of an advance blackout notice, and finally provision of a compensation for blackout damage from the local electricity supplier (from 0% to 25% of the monthly electricity bill paid by the consumer).

The data suggest that the median damage caused by a blackout lasting one hour is around 501-1’000 CHF, and decreases to 0-500 CHF if the blackout is announced with a 24 hour notice. This relatively small figure should be interpreted in light of the composition of the sample, largely made up of small firms with less than 50 employees, and considering that magnitude of blackout damage tends to increase with electricity consumptions. Indeed, the blackout damage hovers around 10%-20% of the yearly electricity bill for firms with bills below 100’000 CHF/year, and around 10% of the yearly electricity bills for firms with higher consumption levels. The heaviest consequences of blackouts display in terms of cost of labour (inactive workers), damages to information and communication technologies and data privacy and availability, lost turnover, and finally damaged machinery. More than half of the respondents own at least one back-up device, such as a UPS, a generator, or a back-up connection to the distribution grid. More than one third is moreover insured against the adverse impacts of blackouts.

The discrete choice experiment included in the survey provides instead interesting hints as regards the preferences of business consumers with respect to blackout duration, availability of advance notice, and provision of a monetary compensation for blackout inconvenience. Longer blackouts harm more, but the negative impact of any additional minute of blackout is decreasing with blackout length; moreover, business consumers having a back-up connection to the distribution grid are less impacted by blackout duration. Receiving advance blackout notice helps reducing the blackout damage substantially, but there is a large heterogeneity among consumers in this respect. Finally, only 65% of the survey participants evaluate positively the availability of a monetary compensation for the blackout inconvenience; the impact of receiving a compensation is however rather small and varies substantially across respondents.

Interestingly, the results collected through the discrete choice experiment show that almost 40% of the respondents always chose the blackout scenario with the shortest blackout duration, disregarding the availability of both advance blackout notice, and monetary compensation. This kind of behaviour, called “lexicographic preferences” among economists, may either witness an extreme importance of blackout duration for consumers, or reveal the use of “heuristics”, i.e. a simplified decision-making procedure, when completing the survey. This finding suggest that any analysis concerning the behaviour of businesses should carefully consider the way in which these kind of consumer reach their final decisions as regards their own energy supplies and consumption patterns: individual behaviours display a sizeable heterogeneity and the assumption of a profit maximising behaviour is not necessarily the most appropriate in all contexts.

Electricity: a homogeneous good eliciting heterogeneous reactions strongly impacted by psychological traits

All in all, the two studies suggest that even if electricity is a homogeneous good often absorbing a relatively small share of the monthly budget, the perceptions of households and businesses as regards the impact of blackouts are also driven by the perceived trade-off between security and environmental sustainability of the own electricity supply. Individual preferences are moreover very heterogeneous, and often driven by behavioural, attitudinal, and cognitive drivers.

Electricity suppliers may use this kind of information for designing supply contracts meeting the needs and preferences of each consumption segment, with customized security levels, variable shares of renewable-based generation, and increasing or decreasing contractual complexity. Policy makers, on the other hand, should be aware that disregarding the behavioural, attitudinal, and cognitive drivers of consumer behaviour might lead to biased estimates of the value of security, and ultimately to investments that might be sub-optimal with respect to the trade-offs that citizens and firms perceive among security, sustainability, and affordability.

Behavioural and attitudinal drivers are often specific to the context and evolve over time. The analyses including this kind of drivers may be seen as too detailed to be included in the uniform methodology adopted in the European Union for the functioning of wholesale electricity markets and the evaluation of the national reliability standards. Nonetheless, they can provide useful hints to complement this methodology, detect the aspects of security that are more important for each consumption segment, and finally provide suggestions as regards the strategies that could best meet the expectations of the citizens and local economic activities.

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IAEE/Affiliate Master Calendar of Events

(Note: IAEE Cornerstone Conferences are in boxes)

Date	Event and Event Title	Location	Supporting Organizations(s)	Contact
2021				
Sept 13-14	BIEE Oxford 2021 Research Conference *Energy for a Net Zero Society:*	Oxford, U.K.	BIEE	Debbie Heywod http://www.biee.org
Postponed to 2021 Dates TBA	3rd IAEE Southeast Europe Symposium *Delivering Responsible Infrastructure and Energy Solutions*	Tirana, Albania		Erlet Shaqe https://see20.iaee.org/
2022				
Postponed to 2022 Dates TBA	8th Latin American Energy Economics Conference	Bogota, Colombia.	ALADEE	Gerardo Rabinovich
July 31-August 3	43rd IAEE International Conference *Mapping the Global Energy Future: Voyage in Unchartered Territory*	Tokyo, Japan	IEEJ/IAEE	Yukari Yamashita https://iaee2022.org/
September 21–24	17th IAEE European Conference *The Future of Global Energy Systems*	Athens, Greece	HAEE/IAEE	Spiros Papaefthimiou http://haee.gr/
2023				
February 5-8	44th IAEE International Conference *Energy Market Transformation in a: Globalized World*	Saudi Arabia	SAEE/IAEE	Yaser Faquih
Postponed to 2023 Dates TBA	18th IAEE European Conference *The Global Energy Transition: Toward Decarbonization*	Milan, Italy	AIEE/IAEE	Carlo Di Primio https://www.aiee.it/
2024				
June 23-26	45th IAEE International Conference *Overcoming the Energy Challenge*	Izmir, Turkey	TRAEE/IAEE	Gurkan Kumbaroglu http://www.traee.org/
2026				
May-June	46th IAEE International Conference *Forces of Change in Energy: Evolution, Disruption or Stability*	New Orleans	USAEE	www.usaee.org

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The following individuals joined IAEE from 1/1/2021 to 3/31/21.

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CPEEL
NIGERIA

Alexander Micheal Akpan
CPEEL
NIGERIA

Ahmad Al Khowaiter
Saudi Aramco
SAUDI ARABIA

Maha K Al Thani
QATAR

Othman Alsaleh
KAPSARC
SAUDI ARABIA

Ilyas Amzil
Universite Paris Saclay
FRANCE

Tolulope Ayokanmi Ayeni
CPEEL
NIGERIA

Jee Young Bae
The Institution for Democracy
Republic of Korea

Ranjula Bali Swain
Stockholm School of Economics
SWEDEN

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INSA Strasbourg
FRANCE

Ellen Beckstedde
KU Leuven & Vlerick Business School
BELGIUM

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FRANCE

Jonas Bender
University of Kassel
GERMANY

Darryl Biggar
Australian Competition and Cons Com
AUSTRALIA

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Universidad Nacional Autonoma de Me
MEXICO

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FRANCE

Gianluca Bruno
University of La Sapienza
ITALY

Pawel Brusilo
Wroclaw Univ of Econ and Bus
POLAND

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GAIADIS transition energetique
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UNITED KINGDOM

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Central South University
CHINA

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ENGIE
FRANCE

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University of Maryland
USA

Wenti Du
Akita International University
JAPAN

Abadi Tochukwu Emmanuel
NNPC
NIGERIA

Ediri Ejoh Emmanuel
CPEEL
NIGERIA

Mmagu Afamefuna Emmanuel
CPEEL
NIGERIA

Dana Engelhardt
Enervis Energy Advisors GmbH
GERMANY

Okunlola Olusola Ezekiel
CPEEL
NIGERIA

Bela Figge
Georgia State University
USA

James Flynn
University of Colorado Boulder
USA

Kathryn Forsmark
University of Denver
USA

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FRANCE

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SPAIN

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AUSTRIA

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Vallourec O. & G Nigeria Ltd
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NIGERIA

Chukwudi Okpalajiaku
Emerald Energy Institute - UNIPORT
NIGERIA

Stephanie Oltra Oro
Cour des comptes
FRANCE

Kutluhan Pak
RTE
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Daniel Pastor
The University of Texas at El Paso
USA

Margarita Patria
Charles River Associates
USA

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AIEE
ITALY

Daniel Posmik
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Purdue University
USA

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University of Iowa
USA

Chiara Ravetti
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Clement Renoir
ETH Zurich
SWITZERLAND

Elias Ridha
RWTH Aachen
GERMANY

Musa Sadauki
NNPC
NIGERIA

Ochuole Queen Salami
NIGERIA

Anita Schiller
Lancaster University
UNITED KINGDOM

Gabriele Serani
University of La Spienza
ITALY

Xi Shen
CHINA

Georgi Shengelia
GNERC
GEORGIA

Cosimo Sisto
SCS Innovations srl
ITALY

Cheri Smith
Covenant Solar Initiative
USA

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CHINA

Björn Steigerwald
TU Berlin
GERMANY

Kota Sugimoto
Tokyo Foundation for Policy Rsch
JAPAN

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CPEEL
NIGERIA

Nguyen Vu Thang
UNITED KINGDOM

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GREECE

Tubi Oluwaseun Theophilus
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NIGERIA

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UNITED KINGDOM

Evonne Tran
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USA

Georgeson Victor Ugochukwu
Dept of Petroleum Resources
NIGERIA

Omar Urdaneta Martinez
FTI Consulting
USA

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King Abdullah Petroleum Studies
SAUDI ARABIA

Calendar

15-16 July 2021, Argus Live: Carbon Markets and Regulation at Online. Contact: Phone: +442077804304, Email: charlotte.milman@argusmedia.com URL: http://go.evvnt.com/782639-2?pid=204

20-21 July 2021, Power2Drive Europe Conference 2021 at ICM - Internationales Congress Center Munchen, Messe Munchen GmbH, Munchen, Bayern, 81823, Germany. Contact: Phone: +497231585980, Email: krucker@conexio.expert URL: http://go.evvnt.com/739358-0?pid=204

20-21 July 2021, EES Europe Conference 2021 at ICM - Internationales Congress Center Munchen, Messe Munchen GmbH, Munchen, Bayern, 81823, Germany. Contact: Phone: +497231585980, Email: krucker@conexio.expert URL: http://go.evvnt.com/739357-0?pid=204

20-21 July 2021, EM-Power Europe Conference 2021 at ICM - Internationales Congress Center Munchen, Messe Munchen GmbH, Munchen, Bayern, 81823, Germany. Contact: Phone: +497231585980, Email: krucker@conexio.expert URL: http://go.evvnt.com/739360-0?pid=204

20-20 July 2021, Green Hydrogen Conference 2021 (Virtual) at Online, Germany. Contact: Phone: 49723158598205, Email: maass@solarpromotion.com URL: https://go.evvnt.com/742329-0?pid=204

21-23 July 2021, The smarter E Industry Days at Virtual. Contact: Email: bechtold@solarpromotion.com URL: http://go.evvnt.com/793834-0?pid=204

21-23 July 2021, EM-Power Europe 2021 at Messe Munchen, Messegelande, Munchen, Bayern, 81829, Germany. Contact: Phone: +49 7231 58598-0, Email: info@em-power.eu URL: https://go.evvnt.com/603442-0?pid=204

25-28 July 2021, 44th IAEE International Conference, Mapping the Global Energy Future: Voyage in Unchartered Territory at Tokyo, Japan. Contact: Phone: 216-464-5365, Email: iaee@iaee.org URL: www.iaee.org

03-12 August 2021, Renewable Energy Power Purchase Agreements at Live Online Course. Contact: Phone: +65 6325 0215 , Email: abigail@infocusinternational.com URL: https://www.infocusinternational.com/pparenewable

24-26 August 2021, Power2Drive South America 2021 at Expo Center Norte, 333 Rua José Bernardo Pinto, Vila Guilherme, São Paulo, 02055-000 , Brazil. Contact: Phone: +49 7231585980, Email: info@intersolar.net.br URL: http://go.evvnt.com/603525-0?pid=204

24-26 August 2021, Eletrotec + EM-Power South America 2021 at Expo Center Norte, 333 Rua José Bernardo Pinto, Vila Guilherme, São Paulo, 02055-000 , Brazil. Contact: Phone: +497231585980, Email: info@intersolar.net.br URL: http://go.evvnt.com/603529-0?pid=204

24-26 August 2021, Intersolar South America 2021 at Expo Center Norte, 333 Rua Jose Bernardo Pinto, Vila Guilherme, Sao Paulo, 02055-000, Brazil. Contact: Phone: +497231585980, Email: info@intersolar.net.br URL: http://go.evvnt.com/603503-0?pid=204

25-26 August 2021, Intersolar Summit Brazil Nordeste at Ceara Events Center, 999 Avenida Washington Soares, Edson Queiroz, Ceara, 60811, Brazil. Contact: Phone: +49 7231 58598-0, Email: info@intersolar-summit.com URL: https://go.evvnt.com/643272-0?pid=204

August 31 - September 02 2021, Electric Vehicles & the Grid at Live Online Course. Contact: Phone: +65 6325 0215 , Email: abigail@infocusinternational.com URL: https://www.infocusinternational.com/ev

08-15 September 2021, LNG: Supply, Demand, Pricing & Trading at Live Online Course. Contact: Phone: +65 6325 0215 , Email: abigail@infocusinternational.com URL: https://www.infocusinternational.com/lng-online

13-22 September 2021, Power Purchase Agreement at Live Online Course. Contact: Phone: +65 6325 0215 , Email: abigail@infocusinternational.com URL: https://www.infocusinternational.com/ppa-online

13-14 September 2021, BIEE Research Conference at Worcester College Oxford. Contact: Email: conference@biee.org URL: https://www.biee.org/conference-list/energy-net-zero-society/

21-23 September 2021, Latin American Refining Technology Conference at Hotel Las Americas, Anillo Vial, Sector Cielo Mar, Cartagena de Indias, Colombia. Contact: Phone: +44 207 384 8006, Email: matt.maginnis@energycouncil.com URL: https://go.evvnt.com/736438-0?pid=204

27-29 September 2021, Reuters Events: Renewable Finance and Investment 2021 at Online. Contact: Phone: +442075367259, Email: Emily.Domange@thomsonreuters.com URL: https://go.evvnt.com/801800-0?pid=204

12-14 October 2021, SPE Russian Petroleum Technology Conference at Technopark Skolkovo, Bolshoy Boulevard 42, Building 1, Moscow, 143026, Russia. Contact: Phone: +74952680454, Email: lkhalmuradova@spe.org URL: http://go.evvnt.com/773176-0?pid=204

12-22 October 2021, Downstream USA 2021 at NRG Center, 1 NRG Park, Houston, Texas, 77054, United States. Contact: Phone: +442075367253, Email: sasha.marks@thomsonreuters.com URL: https://go.evvnt.com/783332-2?pid=204

13-14 October 2021, Reuters Events Offshore & Floating Wind Europe 2021 at Online, United Kingdom. Contact: Phone: +4402075138976, Email: Lindsay.Coulson@thomsonreuters.com URL: https://go.evvnt.com/799954-0?pid=204

18-20 October 2021, ees South America 2021 at Expo Center Norte, 333 Rua Jose Bernardo Pinto, Vila Guilherme, Sao Paulo, 02055-000, Brazil. Contact: Phone: +49 7231 58598-0, Email: info@intersolar.net.br URL: http://go.evvnt.com/603509-0?pid=204

18-20 October 2021, Power2Drive South America 2021 at Expo Center Norte, 333 Rua Jose Bernardo Pinto, Vila Guilherme, Sao Paulo, 02055-000, Brazil. Contact: Phone: +49 7231 58598-0, Email: info@intersolar.net.br URL: http://go.evvnt.com/603525-0?pid=204

18-20 October 2021, Eletrotec + EM-Power South America 2021 at Expo Center Norte, 333 Rua Jose Bernardo Pinto, Vila Guilherme, Sao Paulo, 02055-000, Brazil. Contact: Phone: +49 7231 58598-0, Email: info@intersolar.net.br URL: http://go.evvnt.com/603529-0?pid=204

20-21 October 2021, Carbon Capture Technology Conference & Expo at Bremen Exhibition Hall 4, 101 Hollerallee, Bremen, 28215, Germany. Contact: Phone: +44 1483330018, Email: charlie.brandon@trans-globalevents.com URL: https://go.evvnt.com/784301-0?pid=204

20-21 October 2021, Hydrogen Technology Conference & Expo at Bremen Exhibition Hall 4, 101 Hollerallee, Bremen, 28215, Germany. Contact: Phone: +441483330018, Email: charlie.brandon@trans-globalevents.com URL: https://go.evvnt.com/784299-0?pid=204

23-24 November 2021, SPE Eastern Europe Subsurface Conference | 23-24 November 2021, Kyiv, Ukraine at TBC, Kyiv, 02000, Ukraine. Contact: Email: kdunn@spe.org URL: https://go.evvnt.com/790163-0?pid=204

November 30 - December 02 2021, 2021 Coal Association of Canada Conference at Sheraton Vancouver Wall Centre, 1000 Burrard St, Vancouver, British Columbia, V6Z 2R9, Canada. Contact: Phone: 17807579488, Email: info@coal.ca URL: http://go.evvnt.com/632221-0?pid=204

14-16 December 2021, Power2Drive India 2021 at Bombay Exhibition Centre, Western Express Highway, Mumbai, Maharashtra, 400063, India. Contact: Phone: +497231585980, Email: info@intersolar.in URL: http://go.evvnt.com/604710-0?pid=204

14-16 December 2021, Intersolar India 2021 at Bombay Exhibition Centre, Western Express Highway, Goregaon East, Mumbai, Maharashtra, 400063, India. Contact: Phone: +49 7231 58598-0, Email: info@intersolar.in URL: http://go.evvnt.com/604701-0?pid=204

23-24 February 2022, 14th International Conference on Biofuel and Bioenergy at United States. Contact: Phone: 7588755836, Email: biodiesel@scientificmeets.com URL: https://biodiesel.conferenceseries.com/

July 31 - August 03 2022, 44th IAEE International Conference - Mapping the Global Energy Future: Voyage in UncharteredTerritory at Tokyo, Japan. Contact: URL: www.iaee2022.org

21-24 September 2022, 17th IAEE European Conference: The Future of Global Energy Systems at Athens, Greece. Contact: URL: www.haee.gr

05-08 February 2023, 45th IAEE International Conference: Energy Market Transformation in a Globalized World at Saudi Arabia. Contact: Email: yasser.faquih@gmail.com URL: www.iaee.org

23-26 June 2024, 46th IAEE International Conference, Overcoming the Energy Challenge at Istanbul, Turkey. Contact: Phone: 216-464-5365, Email: iaee@iaee.org URL: www.iaee.org

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Energy Economics Education Foundation, Inc.
28790 Chagrin Boulevard, Suite 350
Cleveland, OH 44122 USA