Power Finance & Risk

PFR Thermal Power Roundtable 2021

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EDITOR'S NOTE

It's been a roller coaster year for project financiers and developers of thermal power plants, who have had to contend with not just a global viral outbreak, but also an unprecedented winter storm and power crisis in Texas, and the fallout of the unexpected ***PJM Interconnection*** *capacity auction results for delivery year 2022/2023.*

The most recent of these events was the PJM Base Residual Auction, which had been pencilled in for May 2019, but was ultimately held in May 2021, after two years of delays due to a back-and-forth between PJM and the US ***Federal Energy Regulatory Commission*** *(FERC) over the Minimum Offer Price Rule (MOPR).*

However, the highly anticipated auction fell short of many market participants' expectations due to the resulting low clearing prices. The $50/MW-day capacity price across most of PJM, compared to $140/MW-day in the last auction, which was held in 2018, has since led to tough conversations around CCGT refinancings and new-builds in the RTO.

Just a few months prior, winter storms walloped Texas, leaving around four million people to wait out rolling blackouts and sending power prices skyrocketing to ***ERCOT****'s ceiling of $9,000/MWh.*

As much as 46 GW of generation was forced offline, of which some 28 GW was thermal and 18 GW a mixture of wind and solar, according to ERCOT.

Unsurprisingly, the crisis has reignited the debate over ERCOT's somewhat insular, energy-only market structure, which lacks the capacity markets and penalties that are designed to ensure reliability in other markets, such as PJM.

Meanwhile, carbon capture, utilization and storage (CCUS) continues to be a hot topic, especially when it comes to retrofitting thermal power plants with such equipment, amid a growing ESG consciousness among investors.

To delve deeper into these topics and more, ***Power Finance & Risk*** *brought together an expert panel of finance, development and investment officials to share their perspectives and predictions. While the resulting debate may not immediately solve all of the challenges facing thermal generation assets, we hope that the nuanced viewpoints presented provide food for thought and inspires further conversation.*

Taryana Odayar
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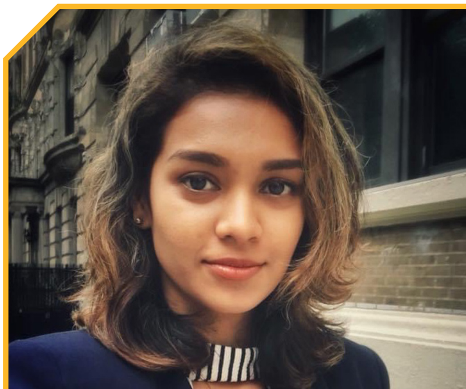

Taryana Odayar, Editor, *Power Finance & Risk* (Moderator)

Taryana Odayar, PFR: Lets start off the discussion with the PJM capacity auction for delivery year 2022/2023. It was a long awaited auction but many market participants were disappointed with the low clearing prices. Did the results come as a surprise?

Susan Flanagan, GE EFS: I'll jump in first. I was reminded of the 2012-2013 clearing prices by one of my colleagues, which were at about $16.50. So maybe not quite a record on this one, but certainly lower than many had expected. From our side, I would say it was broadly within our expectations. Compared to the 2021 auction that cleared in 2018, some of the key parameters that really drove the pricing were lowered demand forecasts, lower CONE parameters and higher new-builds from CCGTs – I think there was an incremental 3.5 GW of CCGTs that came in.

Further, this was effectively a spot auction. As a T1 auction, there was a lot of uncertainty around bidding strategies, especially for nuclear and coal, and that potentially drove prices down further.

Himanshu Saxena, Starwood: A number at $50 for the RTO is definitely lower than where we expected the number to be. We also compared it to where the market thought that number would be, which was centered around $80/MW-day. So this seems to be lower than where the broad expectations were, but a lot of points that Susan has made are right. Some things, like the Dominion FRR [fixed resource requirement], are unprecedented, frankly, and I think that market participants hadn't incorporated that in their bid thinking.

The right metric would be what happens with the next auction. We are going to have to put this one in a box and put a wrap around it and see what the future brings, but we don't think this sets up a trend for low pricing going forward. We do see this as a one-time anomaly. What's more interesting is that the LDAs that were expected to break out, whether it's Eastern MAAC or ComEd, continue to break out.

So the thesis that we have had in the past to bet on constrained LDAs is playing out. Eastern MAAC and ComEd cleared lower than where market would have expected, but still they cleared at almost double the price of where the RTO is. So from an investment thesis standpoint, going forward there's got to be more emphasis on constrained zones rather than betting on the PJM RTO itself.

Richard Roloff, LS Power: Just to echo Himanshu's point, LS Power submitted a complaint to FERC ahead of the 2022/2023 capacity auction that unfortunately they didn't act on, but the Dominion FRR was certainly a contributing factor overall. We were obviously disappointed that PJM allowed that to be implemented so quickly and, in our view, without regard to how an FRR should be evaluated and approved.

I take some silver linings from this. We've seen in the last few weeks more accelerated announcements on retiring older, higher-fixed-cost assets that didn't clear. There are a couple of assets that had been slated to shut in the mid- to late 2020s and the owners have now accelerated that to next year. This shows that the market is working as it should to some extent.

The other silver lining here is that we've seen a significant run-up in energy futures in certain parts of PJM since the auction. Now, it's hard to say that there's total causality there. The markets move for a lot of different reasons other than just the forward view on power. It could be natural gas-related, but it is something to watch. The market could be taking a view here that there's going to be tightness going forward and it could be as a result of some of the outcomes that we just saw on the capacity side.

Flanagan, GE EFS: To add on Richard's point, at $50, I would say most of the coal or nuclear plants without any subsidies would not be able to cover that fixed cost. So that could drive further pressure and further retirements as well.

Saxena, Starwood: I think it could separate the nuclear and coal further because this low print could put more pressure on state legislatures to provide subsidies to the nuclear plants. So they might end up being more than OK, but for the coal sector, this is yet another death knell. There's nobody out there looking to subsidize coal. So clearly the coal retirement might get accelerated and the nuclear subsidies actually might get accelerated, too. So we might have two completely different effects from this.

Flanagan, GE EFS: Agreed.

Daniel Englander, Panamint Capital: We don't own any assets in PJM and so we don't pay particular attention to how this auction settled out or what the next auction looks like. One of the reasons why we haven't been active in PJM is that, from our standpoint, state-level policies or individual utility decarbonization plans are working at cross-purposes to the capacity market itself. These state-level policies or utility decarbonization plans are incentivizing certain types of generation that are agnostic to the outcome of the capacity market, but certainly that's where both the public policy and the regulatory push is happening.

From our perspective, it doesn't seem like that's going to stop. It's not like states or utilities are going to start pulling back on decarbonization targets. So the more that happens, the more it will continue to cannibalize activity in the capacity market.

We think the capacity market is broken and that these additional fixes, whether it's Dominion taking FRR or MOPR, are just administrative band-aids that aren't going to fix the fundamental issue of what's happening in PJM, which is that you have all these different policies working at cross-purposes.

Part of our approach is to wait and see where that all shakes out. Because as more renewables get added to the grid, and those renewables come under MOPR because they're part of some sort of subsidy program or some sort of incentive program, that's going to continue to draw capacity dollars away from merchant competitive gas assets that need higher prices in order for them to continue making their debt payments.

So I think it's more of a fundamental view than an outlook on supply and demand and pricing. Over time, we think that the capacity market is just going to continue to break down and become less effective at doing what it was built to do.

Odayar, PFR: What will be the impact of the auction on sponsors trying to finance new-build CCGTs in PJM? Will we see a lull in activity?

Flanagan, GE EFS: There are about 3.5 GW of new CCGTs that cleared the last auction and they had already achieved financial close. There's probably another 2.5 GW that will go into the December auction that have also reached financial close. Beyond that, it will be limited in terms of new-builds. We expect on average maybe one CCGT per year as we get into 2023/2024 – not the auction years but the actual calendar years – and there's certainly pressure on raising the capital for those projects.

There has been pressure on the equity side for a long time, and we've seen unique structures to get those projects financed with sponsors going to Asia, Japan and Korea specifically to raise capital. It'll still be challenged going forward and that was pre-ESG pressures, but ultimately with the limited number of new-builds, if you've got a strong sponsor, a well-structured project, we would expect those projects to still get done.

But I might add, Daniel's comments were quite interesting and I think that over time we're going to need to see a market redesign to enable dispatchable power that's required for reliability of the grid, to get paid in an economic manner in order to support those projects. And with renewables coming on with effectively zero marginal cost, how do those projects get supported? So it's an interesting challenge for the markets to have over the next many years. As renewables penetration increases, as Daniel spoke about, we're going to see this challenge.

Saxena, Starwood: I think folks have to, frankly, stop building new gas-fired power plants in PJM. There is really no market signal. If you look at the history of performance for the new-builds that have been built in PJM over the last three or four years – I won't name any developers, but you all know what I'm talking about – in a handful of projects, the equity has been completely wiped and the mezz lenders have taken the keys to those projects.

So how do you look at the performance of recent new-builds and still put more equity in building new assets is beyond my understanding of why people are making certain investment decisions. We do think that this print further reinforces the idea that unless you're building it in a rate base, just building pure merchant gas-fired power plants is something that people shouldn't be doing.

To both Daniel and Susan's point about redesign of the market, you don't have to go further than what's happening in Texas this week. There is a op-ed piece today [June 17] which talks about California and Texas and says how low payments to gas-fired power plants have resulted in an outcome where folks are not building new gas assets and are also unable to put the capital investments in maintenance or grid hardening or weatherization of these assets that would be needed in a rapidly changing climate.

So how does an owner of a gas-fired power plant justify owning it and maintaining it if 70% or 80% of the time, the power prices are below $20/MW-hour? These assets are going to become insurance products at some point and you've got to figure out a way to pay for this insurance because free insurance doesn't last for very long and you have these catastrophic scenarios in California and Texas, where the lights just go out the moment the heat is at a certain point, or there is a winter storm. So if you want grid reliability, you have to figure out how to pay gas-fired power plants better, because right now the systems and the markets and the mechanism seem to be pretty broken.

Roloff, LS Power: To me, the lesson of this build cycle has been that the financiers and developers and sponsors are about as sophisticated as ever in terms of packaging new-builds and being able to market and attract capital from all over the world. Susan mentioned Korea and Japan, but we've also seen it from the Middle East and Europe as well.

So if you look at what has changed since a huge chunk of these billions of dollars has been committed and invested over the last few years, and maybe PJM is one example or the easiest example because that's where there's been the most growth, we're now at a spot where the capacity market was basically tolled out for a couple of years in terms of the next clear. You have two auctions in quick succession that don't really provide, in my mind, enough chance for market participants to fully respond between one to the next to what market price signals are saying.

You have FERC which seems pretty intent on taking apart some of the protections and premises of the capacity market, not just in PJM but frankly in all the RTOs. Then you have a drop in most of the price levels that supported whatever hedge structure was allowing these projects to attract debt financing, whether it was revenue puts or heat-rate call options or gas netbacks.

We've now had a cycle where these projects have come online and we're able to see how these hedges actually perform and whether they match the capabilities of the units to the investors' and the lenders' expectations. There's been a lot of slippage and a lot of lessons learned.

To Himanshu's point, yes, there's been a number of projects where equity has been meaningfully impaired or, in some cases, fully wiped out of projects that are otherwise two or three years old. The assets will remain. They'll continue to provide critical service to the system, but I think equity investors are seeing that the cost of the capital and the risk that they're taking on probably needs to be repriced for anything new.

Then lastly, it's sort of inherent to the investment opportunity, but these projects take a long time and given how quickly things move across two of the topics that I just referenced there, particularly regulatory and capacity markets, what you are investing into could be much different than what you are getting out three years later when these projects come online. That gap has never been more risky, at least over the last decade, than it seems to be right now.

Englander, Panamint: I wanted to touch on a previous point, which is about willingness to pay for reliability. I think that's the big issue. Even in this auction, it has shown that the market isn't really willing to pay for reliability and on the retail side, rate payers have gotten used to paying a relatively little amount of money for their electricity without a proper understanding of where those rates are going to. It's going to be very hard for utilities or regulators to put back higher prices on to customers on the basis that they're charging them for enhanced reliability, because that's what customers think they've been paying for all along.

The fundamental question, which is across all the markets that we participate in, is this lack of willingness to pay for reliability in juxtaposition to the serious need to actually pay for that reliability. Above everything else, that issue needs to be resolved first, across markets, before we can think about whether it makes sense to invest in new-build assets, which currently we don't think it does.

Odayar, PFR: I also wanted to bring up the fallout of the auction on refinancings of gas-fired assets. Rich, I know that Hummel is one of the newer gas-fired CCGTs in PJM, having come online in July 2018. What are your thoughts around this?

Roloff, LS Power: Yes, certainly. One of the impacts on the term loan B market was that it obviously reset pricing for almost every business with PJM exposure. The broader backdrop is that non-power term loan B levels are about as strong and thriving as ever. So clearly there's this dispersion between our little corner of the market and the rest of the market, which is driven by the challenges that PJM in particular has caused investors here.

Hummel is a great asset. It did have a troubled capital structure before we took it over, but I'm highly confident we're going to refinance whether it's in the term loan B or some other market. Any asset that has come into service in the last few years certainly is eminently financeable. It's just a question of whether investors, sponsors, owners have the right basis and entry points to accept what the market is willing to lend to you today.

Saxena, Starwood: I think the debt markets remain quite open still despite the PJM print. We are monitoring the debt markets closely. We have a couple of term loan Bs ourselves that are trading in the market. So what we saw is that there was a dip in pricing of term loan Bs, that these loans were trading close to par, especially the well performing assets, and they dipped down to 95 or 96 after the PJM auction was announced. Then over the next three or four days, it ramped straight back up to something in the 99s.

So the debt market seemed to have, for the

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most part, shaken off this PJM event from pricing the term loan Bs. So the good credit is still trading close to par. The credit that is challenged has not really recovered as well. So again, a separation between the good credit and the bad credit, or the not-so-good credit, let's say, is showing up in the pricing on the term loan Bs right now.

Odayar, PFR: I did want to also discuss the MOPR (Minimum Offer Price Rule) specifically. It was meant to help boost capacity auction prices but that was clearly not the case here. So what went wrong?

Flanagan, GE EFS: The first thing is that MOPR probably had a limited impact on the results of this auction. There was about 12 GW of nameplate wind and solar that cleared the auction, most with the unit-specific exemptions. What gets interesting if MOPR is still in place, will be when the offshore comes to market. PJM is making a filing in July to FERC, and they expect it to be resolved prior to the December auction, which seems quite aggressive. Clearly there is agreement now at PJM, and certainly FERC is pushing it, for reform and changes to the MOPR rules.

Roloff, LS Power: I think it's pretty clear that Commissioner **Glick** wants to do away with the MOPR in all its forms, whether it's CASPR, BSM, MOPR, whatever acronym is applicable. So it's just a question of when, and what does it look like after that? From what I understand, and by no means am I a specialist on the regulatory or policy side, it would be contentious to basically put it aside. But whether it sits there as an unapplied portion of the tariff or whether it's revoked and nothing put in its place in the immediate gap, it does seem like that's the direction that things are going.

Commissioner **Danly** has come out with a policy statement saying that you need to focus on the reliability signal and the reliability problem, which we've touched on briefly. It doesn't seem to be in vogue, certainly state-by-state, or with RTOs looking to appease FERC, to talk too much about the long-term impacts that these types of decisions will have on reliability. But look no further than California as an example of where they had to make very quick decisions to essentially procure out-of-market resource adequacy through long-term contracting. It wasn't so much that the market was short from a macro supply-demand standpoint, but the type of resources that could respond to thousands of solar megawatts coming offline simultaneously at 5:30pm every day. The market wasn't designed for that.

As these state-preferred resources come into the market, inevitably you're going to see reserve margin planning requirements go way up. I know New York has said that 70% renewables by 2030 would force reserve margins to over 40% from the 18% or 19% that they use for planning now. So if MOPR goes away, and inevitably it seems to be going in that direction, there's going to be longer-term consequences, but nobody wants to pay for it or talk about it right now. Outside of the power specialists on this call and those that we work with every day, I don't think very many people are focused on how long it can take to fix that reliability problem once it's upon us.

"Absent a big move by FERC in the next couple of months, I don't think the auction prospects look any brighter than they were in the last go-around."

Flanagan, GE EFS: Rich, that's a great point on reserve margins and when people really dig into the data, there are some that think reserve margins go even higher depending on the mix of renewables that comes online and where we go, too, with storage. And the correlation of offshore wind with onshore wind could create further challenges. So I think that's a great point – it goes to market design, but just really the overall reliability of the grid, which is so critical. I understand Daniel's point that people think they're paying for that, but if you talk to regulated utilities that are in with their commissions, their regulators every day, they don't really have the flexibility to say, 'We'll just be offline for a day or two, we're not going to spend on reliability.'

Their need and their focus is, for every hour of every day of the year, to be able to supply power to their customers. We've had events, some here in Connecticut, where we've been out of power for a week at a time. **Eversource** is taking some heat on that. It's just not going to be acceptable and it's only going to get more challenged as we add more renewables to the grid.

Odayar, PFR: The next PJM auction has been scheduled six months from now, in December, as PJM tries to get back to its regular schedule of holding one auction a year. What are your forecasts for that auction?

Saxena, Starwood: We are still digesting the results of the last auction and doing our work on wrapping our arms around what the next auction might bring. So I'm not in a position to give you a number, but I can tell you that my hope is that it's more normalized compared to what we saw in the past.

Roloff, LS Power: My crystal ball is about as murky as Himanshu's. There's still time for additional retirements to play out. There's some IMM involvement that does not look terribly promising, but we'll see how it gets implemented in terms of the review of participants' Market Seller Offer Caps. So it's early to say. Hope springs eternal, but it's early and at the same time, for such a capital-intensive industry, some of these decisions that have to be made in the next five or six months, especially for some of these legacy assets, are going to stress some of the owners and constituents to come to terms with things that need to be changed very quickly on the supply side. So it's really tough to sit here today and take a view.

Flanagan, GE EFS: I'll go a little bit out on a limb here and say we would expect some recovery, but there are so many factors. Again, it's now a T-1.5, so the bidding strategies will be challenged. The status of MOPR could potentially be a factor as well, but I don't think we're going to get back to anything near robust pricing in this auction.

Englander, Panamint: We don't think there will be much significant change between this auction and the next auction. Retirements and potential retirements are largely priced in and the big change will be on the regulatory side. As Rich pointed out, it's a slow-moving industry from both the capital side as well as the regulatory side. So absent a big move by FERC in the next couple of months, I don't think the auction prospects look any brighter than they were in the last go-around.

Odayar, PFR: Let's turn the discussion to the Texas power crisis back in February. What has been the impact of winter storm Uri on financing hedged merchant assets there? There has also been renewed dialogue about ERCOT being structured as an energy-only market – is this likely to happen, and should it?

Roloff, LS Power: We don't have a lot of exposure on the table in ERCOT anymore, but it's still a little early to tell. Some observations are that raising the price when the entire region, including imports, are all facing the same weather pattern did little to nothing to actually incentivize incremental supply.

As for the economists' dream of setting ERCOT up as a purely energy-driven market, I'm not sure it served its purpose at the top end when demand was so tight. We're actually seeing a very similar situation, albeit a different market design, out west in California and Arizona where there's so much inter-reliance on imports and transfers from other parts of the system. When everything is stressed at the same time, I'm not sure that the market design does a whole lot at that top end.

So there are questions in my mind: 'Who got burned? And how does it impact next steps? Ultimately, how does Texas solve the problems of the gas system and of having the right supply available?' It doesn't make sense to build a flexible gas resource in Texas. Similarly, my understanding of the battery portfolios in Texas is that because prices stayed so high for so long, they got whipsawed just as badly as many of the traditional resources that underperformed. So until we have a very long-duration, 24- or 48-hour type of solution on storage, I'm not sure that does much to save the day there either.

Then just in terms of financing adjacencies, we've seen that hedging counterparties, banks, many of whom had a lot of exposure to fixed-price offtake agreements financially or physically, their risk committees and their approach to hedging has swung to the far side of conservative and it's just hard to do business there right now even for good assets. Obviously, this always goes in cycles. After you have a big blow-up, everybody pulls in their risk and then over time it'll get relaxed. So I think that'll heal, but I'm not sure that the lessons learned have really led to anything being applied in practice yet that's really going to fix the fundamental problems.

Saxena, Starwood: Rich has made some really good points. From a macro standpoint, Texas is the fastest growing market from a load standpoint in the country. Texas is expected to grow anywhere from 1.5% to 2% a year, which puts it at about 1,500 to 2,000 MW of new load that would be coming on the grid every year. Short of trying to put more wind and solar and batteries on the grid, how do you meet the growing demand in Texas while keeping the reliability the same? Adding more wind and solar is not really the answer to the problem that we are facing.

To Rich's points, even if batteries were there, given this was a five-day event and if you have a one-hour battery, which is what most of the Texas batteries seem to be, what good does a one-hour battery do for you? It's completely useless to be having these one-hour batteries in the system in a storm like Uri, especially if you are looking at a multi-day weather event, whether it's a heat wave or a winter storm. So we do think that the Texas market has to be redesigned.

I think the whole concept of an energy-only market effectively puts it somewhere close to being in a casino. You keep pressing the lever and one day, maybe it happens in five years, maybe it happens in ten years, you'll make a lot of money, but if it happens to be that you were sick that day and didn't go to the casino, you miss out on the big bounty.

So it's really hard to live on this degree of volatility in the cash flows. After February, there was a lot of discussion about the capacity market and then it slowly died down. I do think that in a rapidly growing market and interfacing that with climate change and unpredictable weather patterns, will require the system to start paying for reliability.

It comes back to the same point again that for Texas customers, for decades it used to be that these retailers were offering effectively free energy to their customers and customer bills were $10 or $15 a month. So these customers haven't paid into the system for the last 15 years and when folks complain about their bills going to $10,000 or $14,000 over that one-week period and people are suddenly up in arms, saying, 'Why am I paying so much?', the point is, you are paying effectively for all that you haven't paid in the last ten years. At some point the music stops, and the music did stop and people had to pay up. That will happen more often.

So the choice is, do you pay once every ten years a lot of money or do you pay on a continuous basis so you avoid that unpredictability? That's a fundamental choice that ERCOT is going to have to make. We have made a proposal to Texas to build gas-fired power plants on a regulated rate base. There has been a similar proposal from **Berkshire Hathaway** and that's another way of solving the problem.

Or you can just make these assets regulated assets. That would be another solution, but the way the market is currently set up is not conducive to anybody building new gas plants. There hasn't been new-build gas-fired power plants in Texas for six years now and we see no price signal for folks to go out and build them. So the situation will continue to get worse as time passes because of the changing supply chain in Texas.

Flanagan, GE EFS: Maybe I could add a couple of different thoughts. First, just in the hedge market, especially on the renewables side, these instruments were seen as no-risk instruments and this is a reminder that there is risk, specially to fixed-profile hedges with wind projects. It has really cooled the new additions of renewables into ERCOT, which, as others have said, has been a strong market.

The other point I would add is that the criticality of the grid, with grid monetization being both physical and digital, is important and will be increasingly important as we add more renewables. But I agree with Himanshu that it's really a fundamental flaw to support dispatchable and reliable assets in an energy market. That is something that they need to address – reliability of that grid will only continue to get worse if they don't.

Roloff, LS Power: If I could build on something that Himanshu mentioned with respect to climate change making some of these planning decisions – which have often been based on historical system capabilities – almost obsolete going forward, I think we've done a lot of talking about large gas plants and the traditional model of a centralized power station, but a big part of where LS Power is investing, as an example, is to continue to look for generation opportunities like that but also to diversify into more distributed solutions and more energy services solutions. Because as the amount of capital needed for an incrementally built gas power plant is close to a billion dollars, it's a lot of risk to tie up.

As more states put decarbonization goals on the table and there's a federal push to reduce fossil fuel intensity, the question of stranded costs becomes even more of a concern. We've been investing in demand response, microgrid development, electric vehicle charging networks, RNG companies. These are all things that are a necessary part of the energy transformation, but it's also an area where there's such great opportunity to deploy capital and there are now real market signals that investors can earn a fair return for doing so.

So it's an exciting time. I wouldn't say it's a full pivot away from the very efficient natural gas facilities that provide a very meaningful reliability service for the grid and will continue to do so, but the times definitely are changing. Solar and wind will continue to increase penetration and it's incumbent upon all of us to figure out ways to facilitate that growth.

Flanagan, GE EFS: We think at GE that gas is a force multiplier to allow more renewables penetration. If we think about the evolution in the US, to get from where we are today to 2035 and the decarbonization that's required, there has to be a buildup of all types of renewable resources. We will need gas power generation to support that; it's going to be absolutely necessary for reliability. To Rich's point on stranded assets, there are a lot of things that are being worked on at GE and the DOE and the US government are also supporting demonstration projects to even decarbonize some gas projects.

Carbon capture and hydrogen are a couple of the pre-combustion and post-combustion technologies that can help further decarbonize. What is so critical in the next 10 years to reach the targets of 2035 is, number one, to ensure that you get all the coal off the grid. It's twice as polluting as gas. So that should be a priority whether in PJM or just the United States and indeed globally. It gives you the opportunity to develop the other technologies that will get you to that last 20% of decarbonization by 2050.

Englander, Panamint: It's important to point out that different customers value reliability differently. So maybe the solution in Texas isn't a complete redesign of the market, but instead finding individual customers who desire a higher degree of reliability through microgrids or on-site generation so that they can pay for that themselves as opposed to socializing it across the market.

Our impression, and maybe it's controversial, is that the market worked in Texas exactly how it was meant to work. As you say, customer bills are $10 to $15 a month and the economic rationale is that those customers are perfectly willing to accept a couple of days of blackouts or outages because they're paying so little for their electricity. If they really valued having utility-type reliability, then they'd be willing to pay more. It seems like they're not and so it implies to me that they would be OK with outages like we've seen in Texas in February.

I tend to think that capacity markets are an inefficient solution to encouraging long-term reliability and I think it'll purely come down to, in Texas, customer choice. Provided the customers can have the choice to pay more for reliability on an individual basis, maybe that's a quicker, more efficient solution to managing reliability on a customer-by-customer basis as opposed to doing it market-wide.

Flanagan, GE EFS: I think if you talk to an individual in Texas that has special-needs children, lost power, lost water for almost a week, I'm not sure that they would have anything to say around less reliability. I struggle with that. I suppose the point that Rich made around microgrids certainly has some specific applications and will continue, but to accept the event there as being OK and how a system should work is just, for me, quite challenging.

Saxena, Starwood: I'm not sure I agree, Daniel, with your assessment either. Your argument is very much a capitalist argument. Sink or swim, eyes wide open, buyer beware. That's what you're saying, which makes sense if there are sophisticated counterparties around the table, but if you are a single family, you don't know how the power markets work and you will happily pay the $10 electric bill, but suddenly when a $14,000 bill shows up, you are like 'I never signed up for it.'

So for a market to work the way you describe, everybody has to be highly educated and has to be highly aware of the risk that they are taking. I don't think 90% of the population would understand that that's how this is working, which is why when this happened, the entire political establishment was up in arms around, 'Hey, what is going on here?' They changed their retail business model, they shut down some of the retailers. There is going to be a limit to free markets and to letting people ride with it because most people don't know what they are signing up for.

Englander, Panamint: Sure, but this is public policy in Texas and it has been for a number of years. The people of Texas have consistently voted to turn out elected officials who support these policies. I guess you could say the same thing about any other complicated public policy in that most of the electorate isn't well informed or is voting based on sentiment, but in this case, people have campaigned on these issues and they've won on having basically free or cheap electricity and this is what the voters have responded with. So to say that the voters are uninformed or don't fully understand it is one thing, but on the other hand, these are the people they've elected to put these policies in place.

Roloff, LS Power: I think there's a limit to it. I don't know that folks are uninformed, but I think most folks only think about the electricity when it doesn't work. When they go to the switch and turn it on, the lights come on. Frankly, people have very busy, complicated lives. Why would they be steeped in power market policy and the like? So it's really incumbent on the regulators to have these protective guardrails. It's one thing for elected officials to have their rhetoric, but there was just an abdication of responsibility on the part of the regulators there. To Susan's point, it's horrifying to think about the human needs fallouts of any time that you lose power, whether it's only for a few hours or several days, God forbid.

So again, I don't think it's fair to think that consumers should be sophisticated about the power markets. I just think that it seems reasonable to think that there should be a regulatory construct which is looking out for the greater interest and put a stop or a limitation to some of these programs that effectively just pass through the wholesale prices to customers who really didn't understand what they were signing up for.

Saxena, Starwood: I think at some point you start setting up a system where it becomes like 2008, with the big financial banks. When everything is about to collapse, the system has to then step in and fix things anyway. So you structure a system where socialization becomes the final stop, even if you started with a very competitive market. If this keeps happening, there will be a point in time like what you saw in California with wildfires, where this will become a social cost even if it was never intended to be. So you are getting back to socializing the cost even if you started with a complete, pure competitive market.

Englander, Panamint: But is the solution to build a lot of new assets that are going to be obsolete from a climate perspective in 10 years? Doesn't that get back to the stranded asset issue? If Texas needs 10 GW of new gas-fired generation to manage what may end up being maybe a short-term need, what are those assets going to look like in 10 years? And are they going to be consistent with either federal or state public policy at the time?

Flanagan, GE EFS: Any discussion around obsolete or stranded assets is probably another hour-long conversation, but what I would say is, you need enough of the dispatchable resources and to fix and weatherize the gas systems so you can get gas to the projects, but you need enough to make the system reliable and stable. Of course, you want to make it as affordable as possible, but I think that is going to allow further penetration of renewables even in a Texas market. So unless you want to continue to have these events, which would be destabilizing ultimately, you need to go back to, I hate to say it, some old-fashioned utility planning within the ERCOT system.

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Roloff, LS Power: The outcome here was not an accident. It was a design. It was a function of the way the system works in Texas. It's an intrastate gas pipeline system. It's very thinly regulated and concentrated. The parties who control the distribution of gas there had a lot of capabilities within their contracts and otherwise to act as 100% economic animals when this event happened to redirect or to shut in gas. Coupled with the fact that gas producers and distributors are not incentivized in a state like Texas to make the necessary investments in weatherization of their system, nor are owners of power facilities. So changes have to happen, but it's hard to see the events of February other than a natural conclusion of the way that the multi-system operability in that market has been designed.

Englander, Panamint: Well, I guess that's my point. The market worked how it was meant to work in the sense that people are economic actors in Texas and the design and structure of the market provided acceptance for loss of load reliability for a period of days, because that's how the market is designed to work. If the players in that market haven't accepted that, then they should because that's just the design and structure of the market that has been broadly supported in Texas for two decades.

My question is, in building all this new gas, how much is that going to put up customer bills on a monthly basis? What is the economic impact to rate payers of subsidizing new gas-fired generation in Texas? Is it another $10 a month, effectively doubling customer bills? Is it $100 a month? Do you have a sense of what those costs are going to be and, in addition to that, whether customers are going to be willing to pay for that?

Saxena, Starwood: Our numbers would suggest that that is nowhere close to $100 a month. It's closer to $10 a month than it is to $100 a month. At the end of the day, customers paid $14,000 for a one-week bill. Do you want to do that or do you want to pay $10, $20, $30 a month on a regular basis? That's a choice. That's a basic choice that customers are going to have to make. One separate point on the obsolescence, which has been interesting to watch, is that a lot of gas-fired power plants that are being proposed now are being proposed with carbon capture systems with it.

So there has been a fundamental shift in that people want these assets to not become obsolete. There are assets that are being developed in places like the Midwest that are close to the carbon network and have carbon sequestration hubs nearby, whether it's depleted fields or otherwise, but there's just been a lot more discussions.

These are still very expensive. We've seen some numbers in the $3,000-$4,000/kW range for a brand-new gas-fired plant with CCS attached to it, but we are starting to see customers that are saying, 'I want to buy clean energy.' So there are folks that would buy 100 MW of wind, but we might see substantial new demand for power from clean gas. That might at least reduce part of the risk that these assets will become obsolete.

"We've seen some numbers in the $3,000-$4,000/kW range for a brand-new gas-fired plant with CCS attached to it."

Flanagan, GE EFS: With some of the new credits that will apply to carbon capture, it could at least cover part of those incremental costs, as well as the efficiency hit that the CCGT will take. We're involved in a number of projects demonstrating carbon capture and it is an avenue. It's not going to keep every project on the grid forever, but it is an opportunity to address the amount of gas or dispatchable power that you're going to need, at least as we sit today without a technology that could step in for that.

Englander, Panamint: That's not a real broad-based solution, though. At $3,000-$4,000/kW, it's going to put up customer bills by a lot more than $10 a month. Plus there's never been a successful large-scale carbon capture project. If they're financeable at a commercial level, that may take eight years or 10 years to materialize even with the tax credits that are potentially available for it. So there's still a solution that has to pop up in the near term to resolve some of these reliability issues that also manage to decarbonization and ESG targets.

Flanagan, GE EFS: There's a lot of efforts at the DOE, for instance, to support some of these projects and the research to address the overall cost of adding carbon capture. So I think this will evolve. It's not a solution today, because of the economics, but certainly the technology is there to capture 85% or 90% of the carbon. Certainly, we have the technology for sequestration as long as it's in the right location or has access to CO2 pipes; there's some way to go for it to be economic in the scheme of providing a reliable grid.

Saxena, Starwood: All you have to do is go back to the nuclear subsidies and do the math on what those subsidies are on a dollar-per-ton basis of CO2. Ignoring the property tax base and the employment issues, if you were just to look at this as carbon-free power, the price on some of these subsidies is well north of $100 per ton of carbon. If you were to be able to get that same value for a CCUS, some of those numbers actually might work.

The problem is, if the carbon is at $10 per ton, then the CCUS wouldn't work, but at $100 per ton, it might. So we see a lot more discussion about CCUS projects in Canada where the price of carbon is significantly higher than the price in the US. So it comes down to a price on carbon. How should we do it? You have to pay in the $100 per ton range as the numbers sit today.

Englander, Panamint: Himanshu, how do you handicap the state of Texas ever putting a price on carbon?

Saxena, Starwood: Not in my lifetime! If anything happens, it will be at the federal level. I think it's really a question of saying, 'Do you care about decarbonization? Do you care about reliability?' It's a very complex, multidimensional equation. Everybody will come at it differently. Different states will come at it differently, but interestingly, Texas is the market where the renewable penetration is the highest. There's 20,000 MW that is currently planned. So the problem is coming to them even if they are not ready. ■

