CPower

STATE OF DEMAND-SIDE ENERGY MANAGEMENT IN NORTH AMERICA

2020

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CONTENT

WHAT WILL ENERGY'S FUTURE LOOK LIKE?

1893 World Fair

To those who experienced the illumination first-hand, the combination of brilliant lights against the pavilion's alabaster facades was nothing short of breathtaking.

It was May 1, 1893, at the World's Columbian Exposition in Chicago. That evening, President Grover Cleveland pushed a single button, prompting a hundred thousand incandescent lamps to illuminate the fairground's neoclassical buildings. The sight drew audible gasps of wonder from the opening night crowd.

The fair's patrons may not have realized it at the time, but the future was on display that night in 1893 courtesy of George Westinghouse's polyphase system of alternating current (AC) power generation and transmission, developed by Nikola Tesla.

A hundred twenty-seven years later, we stand on the precipice of energy's evolution and ask the same question that caused more than 27 million Americans to pilgrimage to the World's Fair with the 20th century looming on the horizon:

What will energy's future look like? If you're reading this, it's likely because you're not only curious as to what the grid and energy markets of tomorrow will look like, but you seek insights on what your organization can do today to position for success when the future arrives.

This book seeks to answer those questions with a market by market analysis of the issues, trends, and regulations the experts at CPower feel your organization should understand in 2020 to make better decisions about your energy use and spend.

We're also going to spend a little time exploring the history of how energy has evolved in the US over the 20th century through today. Understanding the past helps us make sense of the present so we can prepare for the future. Unlike water, electricity travels an unpredictable path. An organization that understands where that path has meandered in the past will be in a position to make the decisions today that bring success tomorrow.

Let us begin.

What’s new in 2020?

In last year’s State of Demand-Side Energy Management in North America, we explained that each deregulated energy market in the US has a vision for the future. Exactly how each market planned to achieve that future, however, was a bit unclear.

While the road to energy’s future is a bit more clear in 2020, questions remain as to how individual grids and markets will evolve to accommodate the influx of new resources such as wind, solar, energy storage and other distributed resources.

One of the questions markets across the country face centers on how these resources should be valued in the marketplace. The challenge of resource valuation has been exacerbated by several driving factors concerning renewables:

Renewable resources are popular. People want them. Many state governments really want them, evidenced by the proliferation of renewable portfolio standards that publicly declare a mission for a given state to be fueled by a certain percentage of renewable sources by a certain (fast-approaching) year.

Renewable sources are also intermittent, the most dreaded adjective in energy management because it essentially means not always available to deliver capacity when the grid needs it.

The regulation concerning energy resources largely occurs at the state level from public utility commission to grid operator and electric utility. This proves to be an inconvenient truth in energy markets comprised of multiple states such as ISO-NE, PJM, and MISO. In these multi-state markets, the passing of comprehensive energy regulation is more challenging than is the case in single state markets like California, Texas, and New York.

How then, are grids and markets moving toward a future poised to include an even greater load of clean, renewable resources?”

The future
AND packaged resources

In the past, markets have considered energy resources on a singular basis, whereby each generating resource is evaluated on its individual merits and shortcomings. Consider a traditional coal plant from a reliability standpoint. The plant can run 24/7, producing a known amount of megawatts every day, as long as it has fuel to burn, forever. Granted, coal plants must shut down for maintenance and the like, but this quantifiable certainty is exactly what grids desire and their operators prefer.

Problem is, the future power mix is trending toward renewable sources, not traditional.

Unlike coal, renewables like solar and wind have intermittency associated with them. Suppose the grid needs those resources at a time when the sun isn't shining or the wind isn't blowing. The inherent intermittent characteristics of solar and wind—when evaluated individually—can lead to reliability concerns.

Now consider a renewable resource that is complemented with demand-side resources like energy storage and demand response. Clean resources rendered powerless by intermittency can be offset on the demand-side with either the discharging of an energy storage unit, the dispatching of demand response, or both.

Grids across the US are looking for ways to package available resources to provide cost-effective, reliable power. Markets are trying to figure out how to value these packaged resources in a fair and just manner.

In the pages that follow, we're going to examine the specific ways each market is going about this forward-thinking practice. We're also going to point out the opportunities available for organizations with flexible demand-side resources that can be called upon by the grid operator in times of need.

THE AUTHORS OF THE INTRODUCTION

Deno Damaskos

CPower Sr. Vice President of Market Development

Deno has more than 25 years of experience in the energy markets including distributed generation, demand response, commodity, and energy efficiency. He directs a team of product managers responsible for liaising with ISOs and utilities regarding DR program policy, optimizing CPower's DR forward capacity positions, providing product support, and developing new DR products.

Mathew Sachs

CPower Sr. Vice President of Strategic Planning & Business Development

For more than 15 years, Mathew has helped build cleantech businesses through investment, partnership, and organic sales growth. Prior to joining CPower, he served with National Grid Ventures as Vice President, Distributed Energy & Renewables. Mathew also served as Vice President, Originations at KRoad DG, a private equity platform focused on energy storage and microgrids.

On the Effect of a Pandemic

Just as this book was scheduled to go to print, the coronavirus outbreak was declared a pandemic and fears of a global economic recession began to take hold.

At this point, it is unclear how this pandemic will affect energy markets in the US and beyond. It is something, however, CPower will relentlessly track and decipher. We will regularly publish our findings in forthcoming articles, webinars, and other communications.

At CPower, we have an entire team of experts whose specific job involves immersing themselves in the intricacies of the nation's energy markets. Much of that team has published their insights in the book you're reading right now.

The 2020 State of Demand-Side Energy Management in North America is one of, if not the, most comprehensive resources covering the issues, trends, and regulations organizations like yours need to know concerning the energy landscape in the US.

Although the pages that follow were written before the coronavirus had reached American shores and was declared a global pandemic, we believe this book, in its current iteration, remains an indispensable resource and one you can thoroughly rely on as a guide to your energy future.

As always, we encourage you to reach out to us if you have any specific questions about any and all things energy-related.

It was a privilege to prepare this book for you.

Sincerely,

John Horton
Chief Executive Officer, CPower

FOR THE RECORD

The energy industry is full of jargon. To make things more confusing, our industry has taken the liberty of adopting into everyday use just slightly fewer acronyms than the US Military.

Throughout this book, we are going to do our best to fully explain any terms that might be confusing so you can get to the essence of what's important and what your organization should be focusing on concerning your demand-side energy management.

Let's start with two terms we are going to discuss frequently in this book because they are hot topics in every energy market in the US--distributed energy resources (DERs) and distributed generation (DG).

Unfortunately, there exists no universal standard for how these terms are defined, which can create confusion.

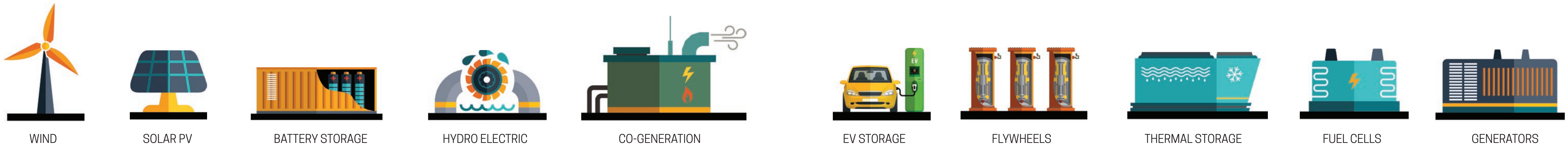
Let's set the record. At CPower, we have adopted the following:

Distributed energy resources (DERs) – is an umbrella term that includes distributed generation (DG) but also includes other demand-side solutions such as demand response. Distributed energy resources are connected to the grid at the distribution level rather than at the transmission level.

Distributed generation (DG) refers to any electricity-generating assets in the distribution grid. These are often, but not always, behind-the-meter. DG can include rooftop solar, back-up generators, microgrids, and more.

Energy storage is often included with DG. However, and this is where a lack of universal definition can lead to confusion, many in the industry do NOT consider energy storage to be part of DG.

To avoid any confusion in this book, we will often refer to "distributed generation and energy storage" when we mean to emphasize energy storage as a key resource in the text.



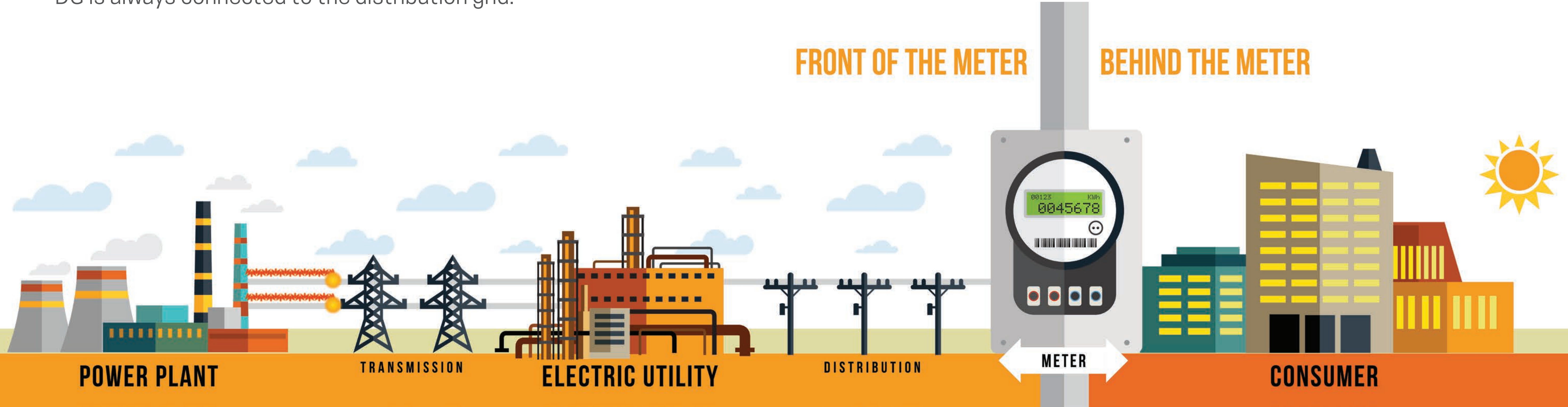
Distributed Energy Resources (DERs) Include:

Distributed Generation (DG) is typically behind the meter but can also be in front of the meter.

DG is always connected to the distribution grid.

DERs also Include:

Demand Response which is always behind the meter DR is a type of DER, but it is not DG.



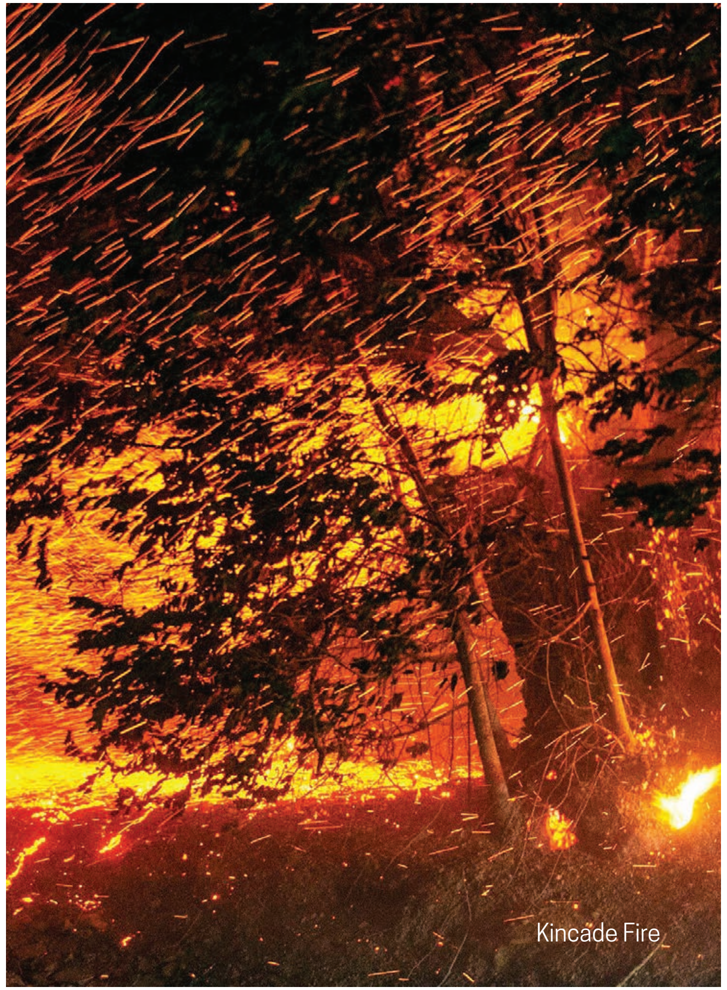
CALIFORNIA

On October 25, 2019, California Governor Gavin Newsom stepped to the podium at the Healdsburg Forest Fire Station in Sonoma County.

The topic on hand was containing the Kincade wildfire, which had raged for two days and would continue another twelve, ultimately setting more than 77,000 acres ablaze across the Golden State.

In his address, Governor Newsom made abundantly clear the cause of the fire, who was to blame, and what the consequences would be for the culprits:

"Years and years of greed. Years and years of mismanagement, particularly with the largest investor-owned utility in the state of California, PG&E. That greed has precipitated in a lack of intentionality and focus in hardening their grid [and] undergrounding their transmission lines. They simply did not do their job. It took us decades to get here, but we WILL get out of this mess. We will hold them to an account that they have never been held [to] in the past. We will do everything in our power to restructure PG&E so it is a completely different entity when they get out



Kincade Fire

of bankruptcy by June 30th of next year (2020). We will hold them accountable for the business interruption and costs associated with these blackouts, and we will do the same with the other two investor-owned utilities in Southern California."

Governor Newsom's strong words echo sentiments that have been grumbled throughout California in recent years by consumers and officials frustrated with what they feel is a broken system.

Trust in utilities was low in 2019. It's lower in 2020.

Consumer trust in California's utilities seems to wane by the day, evidenced by the public outcry that continued to dominate headlines in 2019. The people are fed up with losing power due to negligence (deserved or perceived) on the part of their utility.

The most disgruntled Golden State natives are voting with their feet, seeking better reliability by leaving their utilities and taking up with community choice aggregators (CCAs), which are cities or counties that have taken over key aspects of their own electricity and natural gas procurement and sales from one of the state's three big investor-owned utilities (PG&E, SCE, and SDG&E).

Woolsey Fire

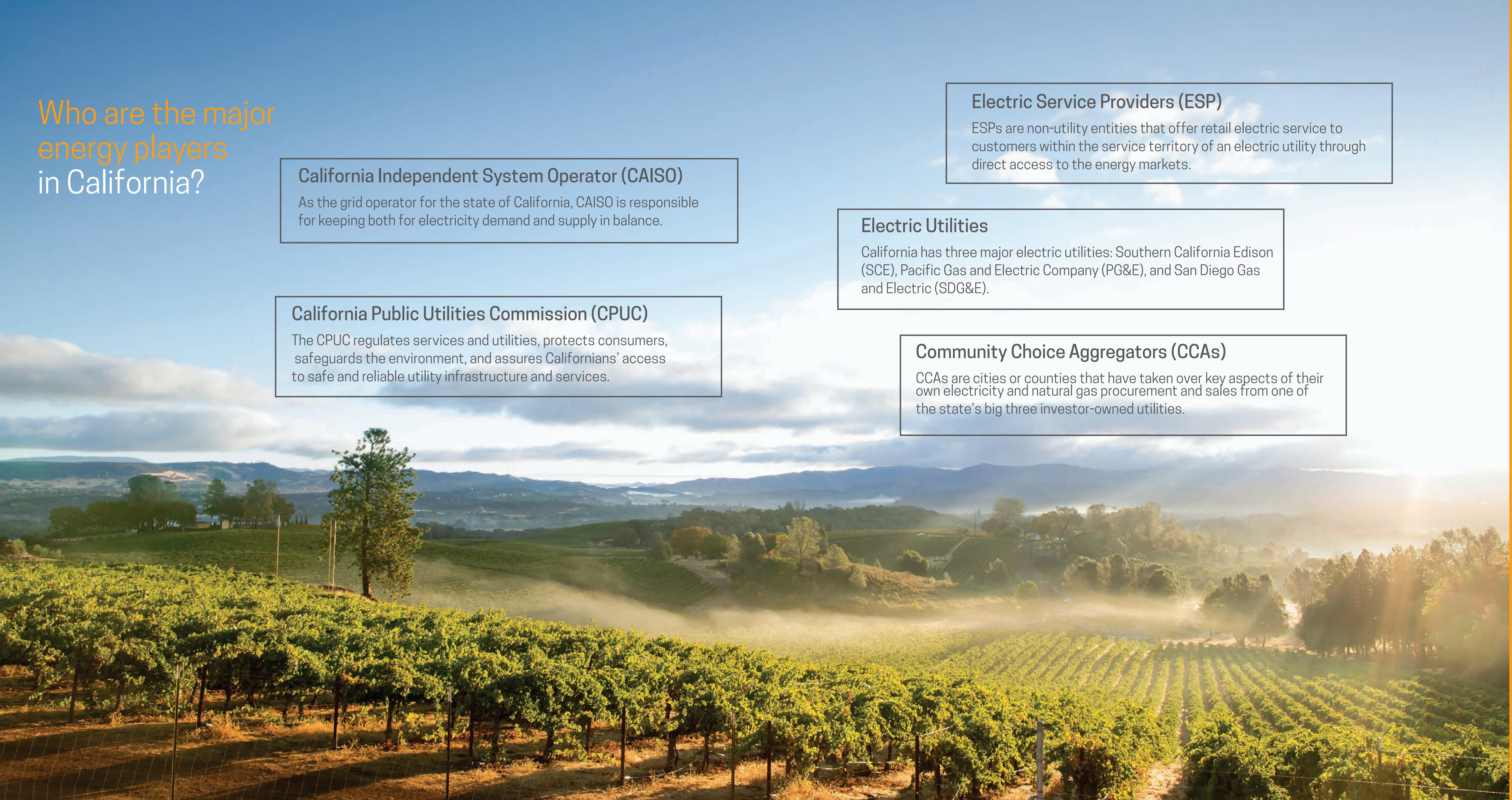
Consumers want reliability.

Consumer desire for reliability is driving widespread interest in microgrid implementation as organizations seek a certain degree of self-sufficiency to hedge against future outages. With demand for microgrids on the rise, legislation at the state level is in the works to both incentivize projects as well as offer opportunities to monetize the ensuing resources.

That California has long been at the forefront in pushing toward a renewable energy future has been well documented. So too have the challenges the state has faced with properly integrating these resources into its grid in a way that ensures reliability.

The state's utilities, energy service providers, and CCAs are trying to procure resource adequacy from a marketplace that, like many energy markets in the US, is having difficulty valuing distributed energy resources. The task of DER valuation falls squarely in the laps of two parties: 1) the California Independent System Operator (CAISO), the state's operator of both the grid and wholesale energy market, and 2) the California Public Utilities Commission (CPUC), which regulates the state's services and utilities.

Both parties have the same goals of providing consumers with safe, reliable and economically sound electricity. But as we'll see in the next few pages, the CAISO and CPUC are struggling to provide a means for ever-popular renewable energy resources to be monetized in California.



Who are the major energy players in California?

California Independent System Operator (CAISO)

As the grid operator for the state of California, CAISO is responsible for keeping both for electricity demand and supply in balance.

California Public Utilities Commission (CPUC)

The CPUC regulates services and utilities, protects consumers, safeguards the environment, and assures Californians' access to safe and reliable utility infrastructure and services.

Electric Service Providers (ESP)

ESPs are non-utility entities that offer retail electric service to customers within the service territory of an electric utility through direct access to the energy markets.

Electric Utilities

California has three major electric utilities: Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric (SDG&E).

Community Choice Aggregators (CCAs)

CCAs are cities or counties that have taken over key aspects of their own electricity and natural gas procurement and sales from one of the state's big three investor-owned utilities.

What's driving energy prices in California?

Parker Dam

Wet year. Low energy prices. In 2019, California's energy prices were low, driven, in part, by the fact that it was a wet year in the West. The abundance of available snow melt and surface water allowed for hydro facilities to generate what would otherwise have to be delivered by more expensive generation units. In dry years, 2014 for example[1], hydro facilities simply can't run as often as they do in wet years and the need for marginal generation resources increases, thereby resulting in higher energy costs.

As of this writing, it is too early in the state's water year to predict whether 2020 will be as wet as 2019 and yield similar prices as last year. In January 2020, roughly the midpoint of the current water year, California's Department of Water Resources reported that eight of its 12 reservoirs were at or above historical average levels, with none below 91% of normal. [2]

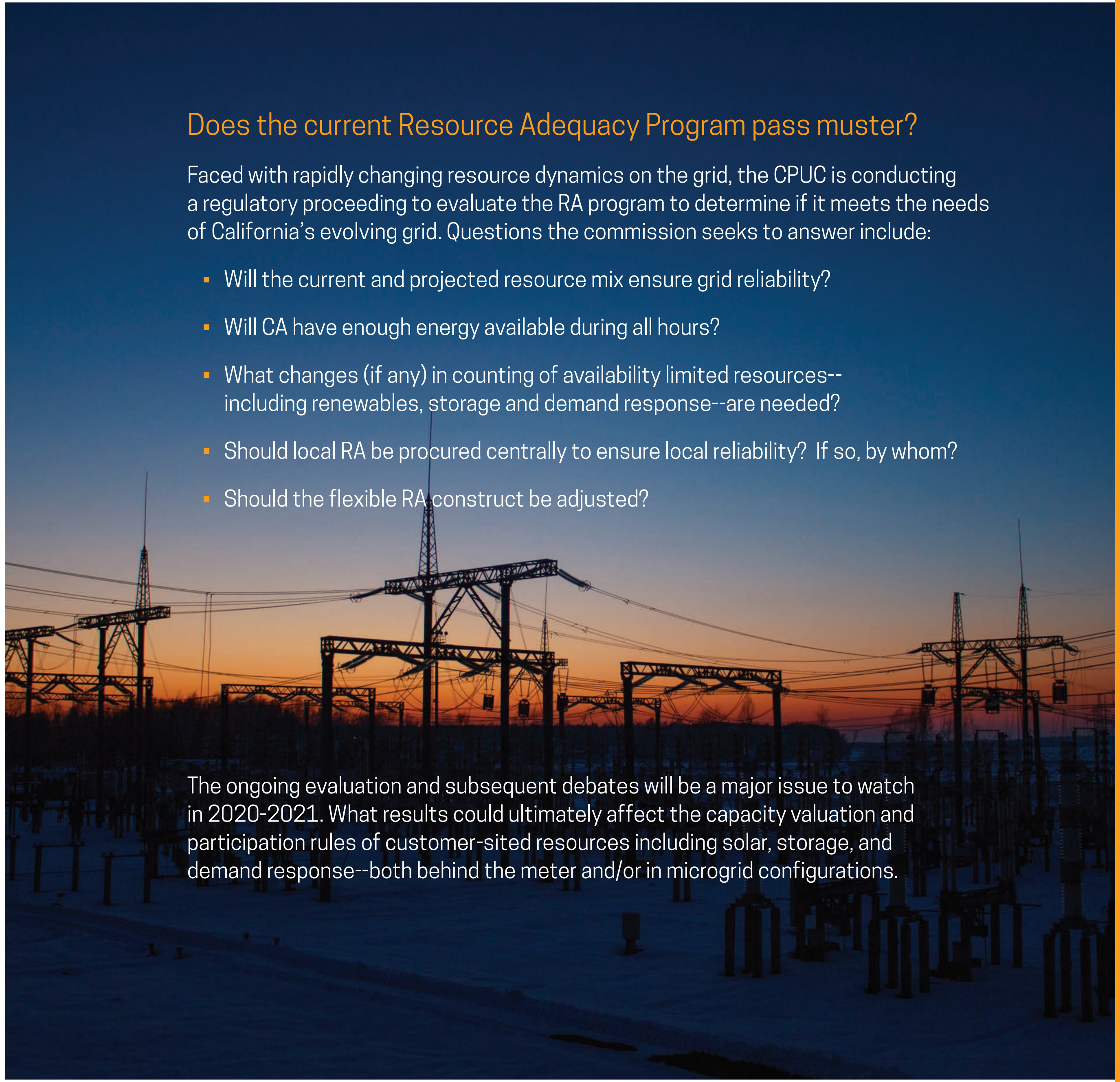
Low energy prices.
High resources.
(For now.)

While electricity rates in California have been traditionally high, wholesale energy prices have been low. The average cost per megawatt-hour of load decreased 44 percent to about $39/MWh for the third quarter of 2019 from $69/MWh in the same quarter of 2018. The decrease in average wholesale electric prices has been primarily driven by a 43 percent decrease in natural gas prices compared to the same quarter in 2018.[3]

Currently, as was the case in 2019, California as a whole is an over-resourced state due to its profusion of resources on the grid that have been built to keep up with the expanding Renewable Standards (RPS) requirements. That abundance, however, appears to be changing.

In its annual Resource Adequacy Report released in August 2019, the CPUC identified (for the first time, on record) a shortfall in system resources. The overall available capacity that can be used to meet all load-serving entities' (LSE) resource adequacy (RA) decreased significantly due to the retirement of 3,122 MW of older gas cogeneration facilities. Increased penetration of use-limited resources on the grid has also raised RA concerns.

To alleviate the shortfall, California's Integrated Resource Planning (IRP) and CPUC ordered 3.3 GW of system RA to be procured by all LSEs (IOUs, CCA's and Electric Service Providers) under the CPUC's jurisdiction and to come online between August 2021 and August 2023. Considering the California grid typically runs at about 35 GW on a non-peak day, the 3.3 GW order is substantial.



Does the current Resource Adequacy Program pass muster?

Faced with rapidly changing resource dynamics on the grid, the CPUC is conducting a regulatory proceeding to evaluate the RA program to determine if it meets the needs of California's evolving grid. Questions the commission seeks to answer include:

- Will the current and projected resource mix ensure grid reliability?
- Will CA have enough energy available during all hours?
- What changes (if any) in counting of availability limited resources--including renewables, storage and demand response--are needed?
- Should local RA be procured centrally to ensure local reliability? If so, by whom?
- Should the flexible RA construct be adjusted?

The ongoing evaluation and subsequent debates will be a major issue to watch in 2020-2021. What results could ultimately affect the capacity valuation and participation rules of customer-sited resources including solar, storage, and demand response--both behind the meter and/or in microgrid configurations.

California continues its push toward a renewable future.

California's Renewable Portfolio Standards (RPS) program was established in 2002 by Senate Bill (SB) 1078 (Sher, 2002). Initially, the program required 20% of electricity retail sales to be served by renewable resources by 2017.

The program was accelerated in 2015 with SB 350 (de León, 2015) which mandated a 50% RPS by 2030. In 2018, SB 100 (de León, 2018) again increased the RPS to 60% by 2030 and requires all the state's electricity to come from carbon-free resources by 2045.

All electricity retail sellers had an interim target to serve at least 27% of their load with RPS-eligible resources[4] by December 31, 2017. According to the CPUC in 2020, retail sellers either met or exceeded the interim 27% target and are on track to achieve their compliance requirements.

How does the CPUC evaluate energy resources in California?

The Integrated Resource Plan (IRP) and Long Term Procurement Plan (LTPP) are planning proceedings to consider the CPUC's electricity procurement policies and programs to ensure California has a safe, reliable, and cost-effective electricity supply.

The IRP and LTTP's competitive procurement mechanisms include:[5]

- Requiring auctions for certain purchases
- Procurement Review Groups (which allow non-market participants to provide feedback on procurement plans in a confidential environment)
- Independent Evaluators that monitor the cost-effectiveness and overall appropriateness of transactions
- Quarterly audits by CPUC

Currently, the CPUC is (and will be throughout 2020) scrutinizing its policies to determine if they do, in fact, yield a qualified fuel mix that serves the state's green ambition and reliability needs. Should the CPUC determine a change to its procurement policies is needed, one of the big questions the Commission will likely ask is how or should the policies be amended so that resources that qualify as RA provide the right characteristics to CAISO.

The challenge of valuing resources in the marketplace

On its website, the CPUC states that the Resource Adequacy program "is designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future."

So what's the problem?

Many energy professionals in California would argue the state's inability to properly value DERs in the marketplace is stymying innovation and evolution on the state's grid that would otherwise take place.

In California, a given resource's capacity value is determined by the resource's ability to either generate or curtail in response to grid operator direction. For demand response programs, this is measured as their ability to curtail during the CAISO's established availability assessment hours. These hours coincide with when the grid is most likely to need extra capacity--namely, in the evening as the sun sets and the state's solar supply goes offline and residential consumption spikes as people come home from work and go about their electricity-powered lives.

Renewable energy sources such as solar are inherently intermittent. Their supply is not continuous or steady. Solar, of course, is only viable during (cloudless) daylight hours.

California has been a leader in creating hybrid energy resources which combine distributed energy resources (including renewables) with energy storage.

So far, so good for the Golden State. Here's the problem.

While customer-sited, behind the meter hybrid resources may participate in California's wholesale energy market as part of demand response, hybrid resources that consist of front-of-meter resources—as are often found in microgrids—are not fully valued by the CPUC as resource adequacy.

Consider a front-of-the-meter solar resource that qualifies as resource adequacy. If the owner of that asset were to add an energy storage resource, the ensuing Qualifying Capacity (QC) value (essentially the MW value that can qualify as RA) would change and thereby cancel the value benefit of the combined resource. Hybrid resources, therefore, are either kept out of the marketplace or they are significantly undervalued.

This situation keeps increasingly popular resilience resources on the sidelines instead of supporting grid needs and allowing for them to monetize their value when not providing support to the customer for daily or Public Safety Power Shut off events (PSPS).

As we suggested in the introduction of this book, renewable resources packaged with demand-side resources such as energy storage and demand response may be a panacea for evolving grids and markets seeking to integrate renewables and overcome their inherent intermittency issues.

Yet, California—the longtime global leader in renewable energy innovation—is lagging behind other US energy markets when it comes to devising a plan to value many DER resources in the marketplace. As a result, the Golden State's march toward energy's future has slowed while these issues work toward resolution.

The state has ample clean energy capacity available to meet its RA requirements now and in the future in accordance with the established goals of the RPS. Unless, however, those renewable resources when packaged with energy storage and/or demand response (hybrid resources) are permitted to both qualify for the RA program and participate in the wholesale market, the standstill will likely continue. For how long depends on whether the CAISO and CPUC can work together in 2020 to establish rules and regulations to allow resources to harness available and developing value streams.

Will 2020 be the year of proper valuation for DERs in California?

That's the million dollar question. Depending on your organization's energy asset portfolio, the question may be worth a lot more.

And now is as good a time as any to remind that predicting when market-altering legislation might be introduced is the ultimate fool's errand in the energy industry. But since you picked up this book looking for answers to the million dollar question, we might as well play the fool and make a prediction.

Will 2020 be the year the CPUC and CAISO agree on how to qualify and value DERs in the retail and wholesale markets in a way that inspires innovation and implementation on both the supply and demand side?

Not likely.

Simply put, too much has to happen and neither party has made the kind of progress to suggest a sensible plan can be introduced, approved, and implemented this year.[6] But that doesn't mean that organizations should throw up their hands, bury their heads in their utility bills and wait for next year.

Let's now focus on what demand-side actions organizations in California can take to position themselves for energy management success in 2020 and beyond.

PG&E dominated 2019 (for all the wrong reasons).

Have we made it clear just how much of the air PG&E's wild year has sucked from the room normally reserved for legislative and regulatory attention in California?

Just in case you skipped ahead to this section, let's run down the 2019 lowlights of California's largest investor-owned utility. About the time we published last year's version of this book, PG&E was accepting responsibility for burning down six towns in Northern California. Since then, they've declared bankruptcy and decreed their intention to pay pennies on the dollar for wildfire and FEMA claims. While sorting through bankruptcy, they initiated a series of Public Safety Power Shut off events (PSPS[7]), which forced outages on millions of Californians. And for an encore, they lit the Kincaid wildfire, burning more than 75,000 acres and triggering evacuations involving more than 100,000 residents during those same PSPS events.

To put it mildly, PG&E and the fallout from their tumultuous 2019 have dominated the focus of California's energy legislators, regulators, and commentators to the point where seemingly little else was discussed at the state level concerning energy policy during the previous year.

It's worth mentioning, additionally, the CPUC has experienced an 80% turnover rate of its commissioners during the last three years. The new commissioners are largely committed to the state's climate goals, but face the unpleasant task of dealing with, among other pressing issues in California, the fallout from the wildfiles.

Everyone in California (and this is a rare occasion where we do mean everyone) wants reliable power. No one benefits from excessive outages, especially incumbent political figures whose electibility in the Golden State can hinge on how they handled the times during their administration when the lights went out.

Simply put, there is so much at stake right now during this critical evaluation and reform process that everything energy-related is up for debate in California. The country is watching as it has for much of the time California has been at the forefront of energy's evolution.

As a result, there aren't any significant, new demand-side products or updates to previous products to report in 2020.

That said, let's talk about the current state of California's demand-side energy with an eye on what the future might hold and why action today on the part of organizations on the commercial and industrial sector could soon lead to big rewards.

Demand-Side Energy Management Opportunities in California

With so much focus on energy reform in California, it can be hard to get a sense as to where organizations should be investing to position for demand-side energy management success in a state whose future is nowhere close to being set.

Here are a few ideas for organizations to consider concerning behind-the-meter energy resource investment:

Resources with zero-carbon emissions are a good investment. (This is California, after all). Diesel generators have recently become popular among residential and commercial consumers fed up with outages. Diesel generators certainly provide much sought-after reliability. But they are fossil fuel based and therefore can not be monetized by participating in demand response programs. It is highly unlikely that regulations on this matter will change in the future.

Resources with the potential to provide grid resilience are also a good investment. The path to monetizing DERs (including behind-the-meter distributed generation--DG--assets) in California hasn't yet been fully established, but it will be. And when the Golden State establishes policies that allow for monetization of renewable integration resources, it's a good bet that the incentives will be set up to reward those resources on which the grid can call on in times of need. Organizations that therefore invest in behind-the-meter renewable resources including energy storage will be in a prime position to reap the rewards of monetization when California inevitably embraces the benefit of packaged resources (renewable + energy storage and/or demand response) as other deregulated energy markets in the US have.

Exploring or outright participating in demand response can help organizations be ready to monetize their DERs (including DG and energy storage) when the time is right. Organizations that are able to help the grid with demand response (DR) stand to be rewarded with revenue streams when California properly addresses its resource valuation problems. Consulting a demand response aggregator (an approved company that facilitates DR in California) is a great way to decide if DR is right for your organization now or in the future.

Automation - fast flexible response of curtailment and eligible DER will be needed in the future as we continue to integrate high volumes of intermittent resources in the state.

Demand Response Programs in California

Demand Response programs pay organizations for using less energy when the grid is stressed or energy prices are excessively high.

The major underlying value of demand response programs in California is the resource adequacy capacity they provide for the grid.

Currently, demand response programs are administered by California's three regulated investor-owned utilities: Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric.

Capacity Bidding Program (CBP) The CBP is an aggregator-managed program that operates with Day-Ahead and Day-Of options and runs year-round in the SCE Territory and May 1 through October 31 elsewhere throughout the state.

Demand Response Auction Mechanism (DRAM) is a pay-as-bid program developed in 2014 under the guidance of the California Public Utility Commission (CPUC) in an effort to harmonize utility-based reliability demand response with CAISO, the state's grid operator.

Base Interruptible Program (BIP) is intended to provide load reduction on the system on short-notice (15-30 minutes) when the utility issues a curtailment notice in response to a system emergency. Customers enrolled in the program will be required to reduce their load down to or below its Firm Service Level (FSL).

In the US Government sponsored report *The 2025 California Demand Response Potential Study*, the Lawrence Berkeley National Laboratory asserted, "Demand response (DR) has the potential to provide important resources for keeping the electricity grid stable and efficient, to defer upgrades to generation, transmission and distribution systems, and to deliver customer economic benefits."

Will 2020 be the year that potential is realized? Time will tell. Consulting a demand response aggregator that can assess your organization's facilities and potential for DR earnings is a sound move whose benefits will be realized in the near future, if not right away.

What is new with demand response in California in 2020?

Demand response is needed during the CAISO's established availability assessment hours, which officially changed in 2018.

The new availability assessment hours have been phased in by utility and program, but all will run until 9 PM year-round in 2020, finally catching up to the CAISO availability assessment hours.

Changing the hours from midday (as they had been previously) to early evening is an attempt to reduce the evening ramp of consumption by providing demand-side resources when solar goes offline and demand increases as people return home from work and increase their household electricity use.

Final Thoughts:

California has no shortage of innovation when it comes to the pursuit of a clean energy future. The state that now requires all newly constructed homes to be outfitted with rooftop solar panels is flush with a base of commercial and residential consumers who've voted with their feet and made the investment in renewable energy sources.

The people of California *want* these resources. They also want to monetize them. Currently, limited opportunities exist to allow these resources to harness potential value streams. As a result, the Golden State's appetite for renewable energy consumption is far heartier than the demand-side management opportunities available for commercial consumers who've led by example in pursuing a green energy future.

Expect that to change.

If the history of demand-side energy management tells us one thing, it's that the vision for the future always precedes the legislation and regulation that draft the rules to get there.

For decades, California's vision has led the charge in the US toward a renewable future. The state's legislation has followed suit with a Renewable Portfolio Standards whose ambition has spread throughout the country. It's time for the regulation to step up and do its part to ensure California's vision of a reliable grid fueled from efficient, cost-effective, non-fossil sources doesn't become a hallucination.

THE AUTHORS

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Diane has more than 20 years of experience in the energy industry, holding positions of increasing responsibility at various utilities including Wisconsin Electric Power Company and Southern California Edison. She is a Graduate of the US Naval Academy, Annapolis, MD and holds an MBA in International Marketing from Loyola Marymount University, CA.

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TEXAS

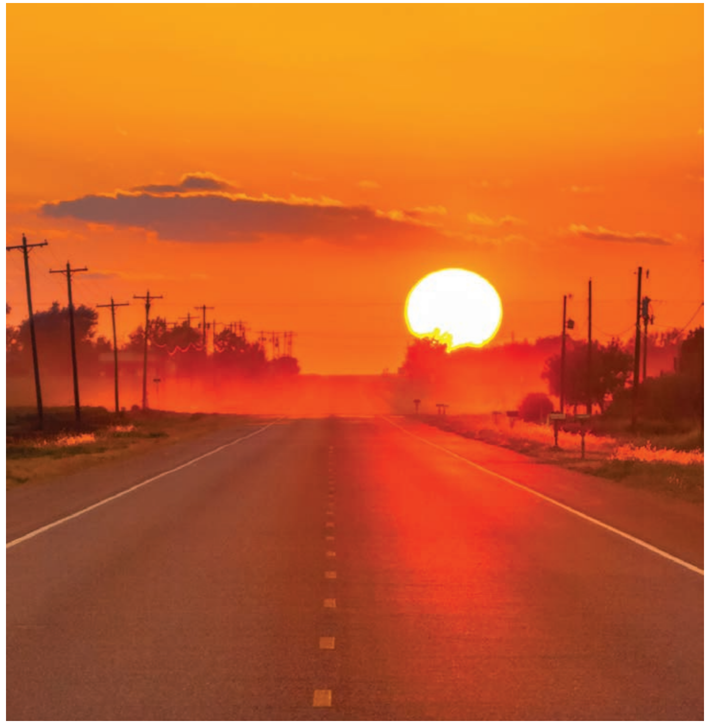
By 2:00 PM CT on August 13, 2019, temperatures throughout most of Texas had smashed across the 100°F threshold.

Like a spiking fever bound to land an unfortunate patient in the emergency room, the temperature in the Lone Star State continued to rise and wouldn't settle until it reached 103° F, a full six degrees above the historic average high for the day.

From their headquarters in Austin, the Electric Reliability Council of Texas watched as electricity demand climbed to the point of threatening the grid's operating reserve margin of 3,000 MW. Anticipating that scorching temperatures would predictably cause electricity demand to rise and infringe on the reserve, ERCOT had issued a conservation call by way of conventional media channels asking consumers to voluntarily reduce their electric consumption between the hours of 3-7 PM.

The temperature continued to rise. So did demand.

At 3:10 PM, ERCOT's operating reserves dipped below 2,300 MW. Without action in the face of rising electrical demand, the state would soon face rolling blackouts. That's when



the grid operator issued a call for an Energy Emergency Alert (EEA1), dispatching the first demand response event in Texas since January 2014. By 5 PM, the event had concluded and the grid returned to normal operations, having never lost power.

Two things of note happened that day in August. Both have to do with the design of the Texas energy market as it relates to grid reliability.

First, the ERCOT grid held its balance, responding as designed when demand for electricity threatened to exceed its supply. Second, the organizations that helped the grid maintain its balance by participating in demand response earned revenue in ERCOT's Emergency Response Service. Participants in ERCOT's Load Resource (LR) program made a killing due to wholesale electricity prices surging past $9,000 a megawatt-hour.

It's by design in Texas. All by design.

What makes Texas's energy market different from others in the US?

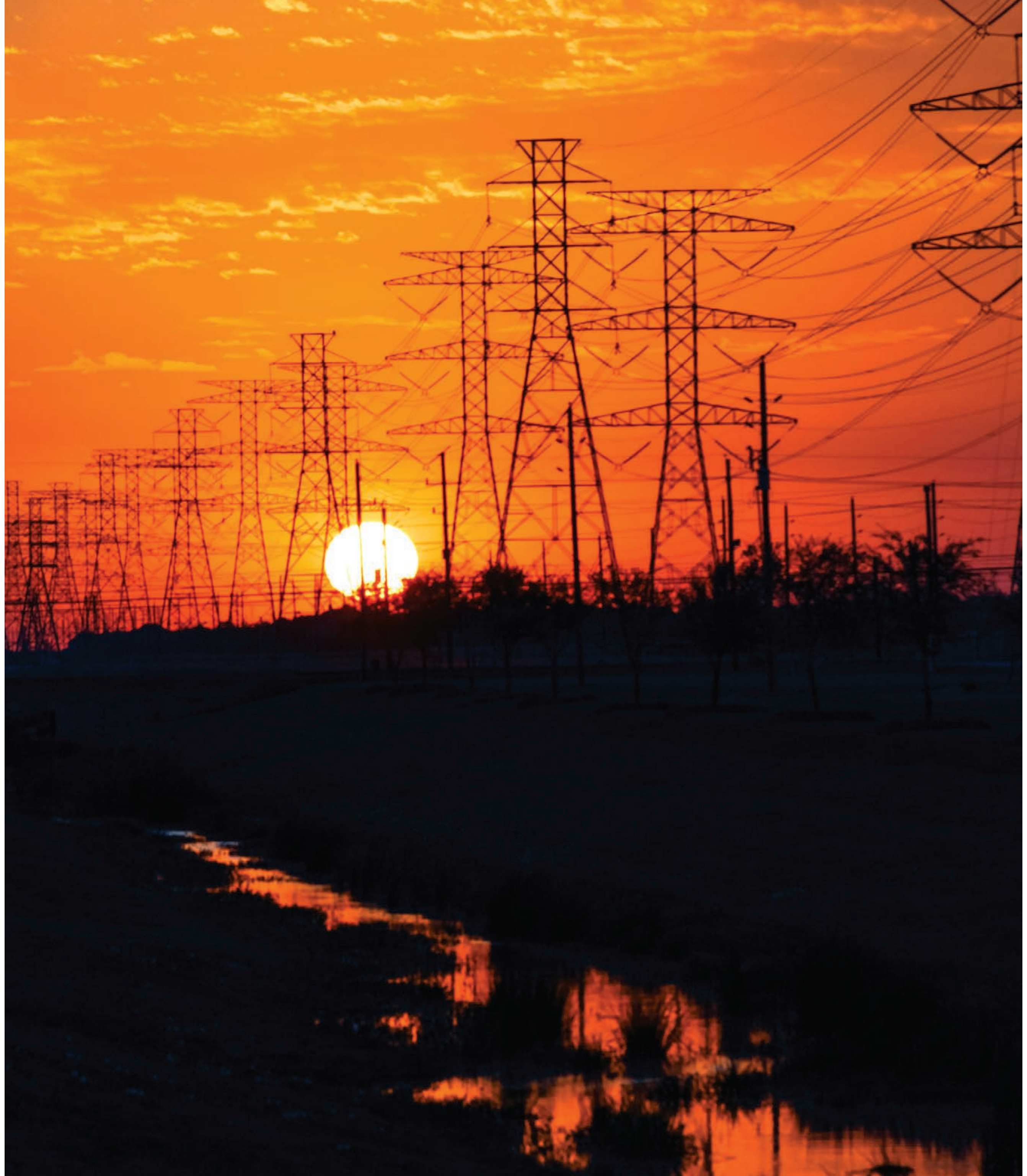
Like Texas, other deregulated energy markets in the US have policies and procedures to ensure grid reliability when electric demand is on the brink of eclipsing supply. Unlike Texas, however, other markets don't rely strictly on economic mechanisms to keep the power flowing.

Some markets--PJM and New England, for example--have forward capacity markets through which the necessary capacity for a given day is procured well in advance.

Here's how a forward capacity market works for participating demand-side resources:

There's a procurement auction into which organizations with available resources offer their capacity. The capacity that is accepted clears the auction at a certain price per megawatt hour.

The goal of a forward capacity market is twofold. First, the grid operator procures all the capacity it needs (or predicts it will need) well in advance of its delivery day, including a reserve should future demand exceed future supply. Second—for



simplicity's sake let's focus on the demand-side —the providers of that capacity have a financial incentive to curtail their load should the grid need it. It works for PJM just as it works for New England. Doesn't work for the Lone Star state, and the event on August 13 of last year proves why there is no reason to mess with Texas.

Texas doesn't have a forward capacity market. Instead, ERCOT maintains a capacity reserve margin, calculated by subtracting the projected peak demand on the grid from the total capacity generation available in Texas.

Why?

By not maintaining a capacity market, ERCOT aims to keep costs incurred by its ratepayers at a minimum by avoiding what they see as an unnecessary surplus of capacity.

OK, says the skeptic (and there are no shortage of industry skeptics who think by not maintaining a capacity market Texas is one hot summer away from its grid shorting out to the dark ages) what happens when electric demand eclipses the reserve margin? How in the name of the Alamo can Texas be sure it has the emergency capacity to thwart a blackout?

Look no further than August 13, 2019 for the answer.

Why the event on August 13, 2019 affirms Texas's market design.

It was hot in Texas on August 13 last year. Real hot. Nolan-Ryan-fastball-under-your-chin-hot. Roasting-armadillos-on-the-driveway-hot. Electric demand across the state predictably spiked. Voluntary (i.e. non incentivized) calls to curtail issued by ERCOT went largely unanswered. (Would you volunteer to shut your A/C off when it's 103° F?)

Then, at 3:10 pm ERCOT dispatched its first wave of demand response. The event lasted less than two hours. Balance was restored to the grid. All was well.

So what makes Texas's market superior (at least in the mind of Texans) to other regions that feature capacity markets? Two reasons:

1. By not having to bolster a capacity market, Texan ratepayers don't have the inflated electricity bills lamented by consumers hailing from markets that procure more capacity than needed.
2. By having an economic trigger whereby the wholesale price of electricity in times of scarcity surges to $9,000/MWh, Texas provides an irresistible incentive for organizations to help the grid in times of need.

In short, the Texas energy market is driven by economics not regulation.

As a result, the market's demand response resources are robust. Why shouldn't they be? Event calls are few and far between and participants are cashing in when called upon by the grid.

Exactly the opposite is happening in California, where participants who are already paying high electricity rates are fatigued from the number of demand response calls they've received over the years. They're not being rewarded much for their curtailed megawatts, either. Capacity prices in the Golden State dipped below the national average years ago and have been stuck there ever since.

The economic-driven design of the Texas energy market doesn't just incentivize emergency capacity in times of need. When it comes to integrating distributed energy resources (DERs) onto its grid, economics are leading the way in the Lone Star State.

Renewable Growth in Texas

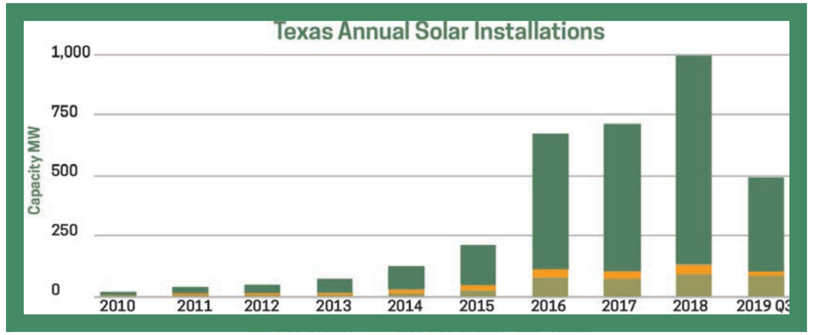
Wind energy has traditionally been the reigning renewable king in Texas. The Lone Star State has nearly 25,000 MW of installed wind powered by 13,000 operating turbines, with an additional 7,000 MW in development.[8]

With a current base of about 2,000 MW, solar has had a modest presence in Texas, by comparison. That's about to change. Economics are the catalyst.

Incentives for Solar Installation

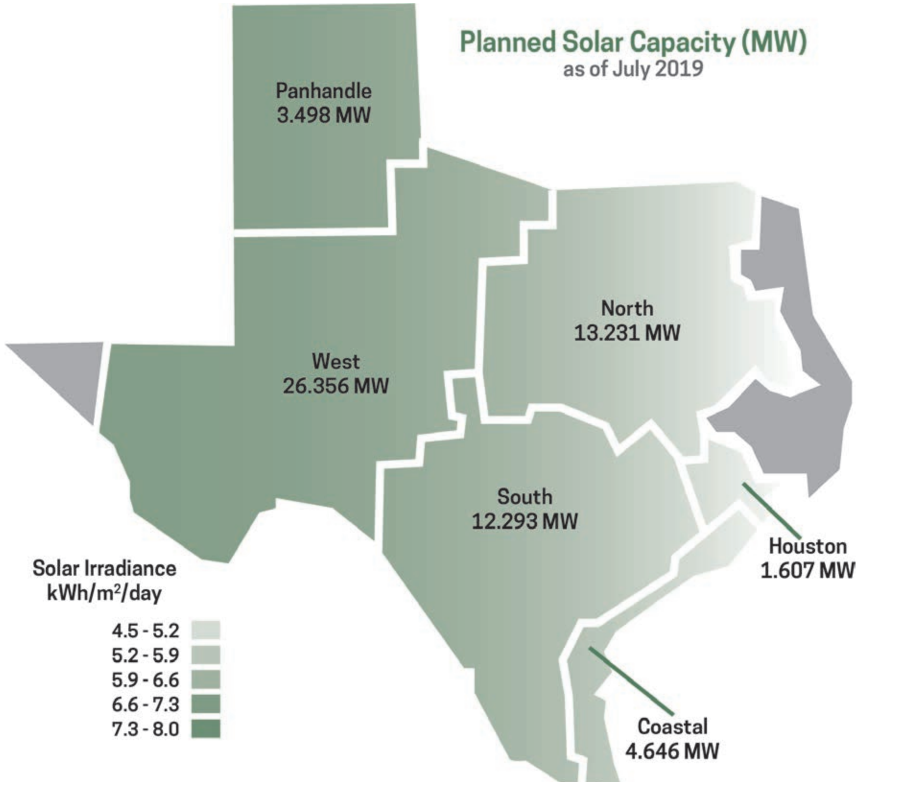
Enacted in 2006, the Solar Investment Tax Credit (ITC) is a federal tax credit that offers a dollar for dollar income tax reduction, based on the amount of investment in solar property. The ITC is a step-down plan meaning the amount of incentive decreases with each subsequent year. For example, the credit was 30% until December 2019. It will be 26% throughout 2020, then it will decrease further to 22% throughout 2021, and drop to 10% for any project completed after January 1, 2022.

Recognizing the urgency, Texans interested in installing solar are acting quickly to take advantage of the federal incentive before the clouds settle. The Lone Star State is projected to grow its solar generation by more than 13,400 MW in the next five years.[9]



Source: SEIA/Wood Mackenzie Power & Renewables, Solar Market Insight©

Utility-scale solar is also growing in Texas. In July 2019, ERCOT announced that nearly 60,000 MW of utility-scale solar capacity was under study in the region. ERCOT acknowledges that it is unlikely ALL of these projects will get built. Nearly 5,900 MW of the total under study, however, reflect signed Interconnection Agreements and may be installed and in-service by the end of 2020.



Source: ERCOT More than a third of the solar capacity under study is in West Texas, where fewer clouds tend to result in less intermittency issues for solar generation.

How Texas wind and solar complement each other to offset intermittency

The challenge for any grid seeking reliability while integrating wind and solar generation lies in overcoming the inherent intermittency associated with renewable resources. Texas's natural summer weather patterns, however, may give the state an advantage during hot months when the grid is at its most fragile.

During the summer, winds in the state tend to blow from the late-afternoon to mid-morning hours, exactly the opposite of when the sun is at its brightest.

ERCOT has high hopes that the complementary nature of wind and solar will help meet future load demands in Texas. The grid operator has devoted significant time and resources to improving its wind and solar forecasting models so it can more accurately predict when intermittency might threaten the grid.

The operative word here is *when* intermittency rears its disruptive head to the chagrin of the grid's supply and demand balance. Unexpected cloud covering is inevitable as are windless afternoons and nights. That's why ERCOT has adopted the progressive approach of packaging renewable sources like wind and solar with energy storage and demand response.

ERCOT's Battery Energy Storage Task Force

Approved on October 23, 2019, ERCOT's Battery Energy Storage Task Force (BESTF) is a non-voting body that reports and provides recommendations to the Technical Advisory Committee. One of the task force's primary goals for 2020 is to introduce a framework for how energy storage resources can participate in Texas's wholesale energy market.

Texas is experiencing an increase in the amount of energy storage resources being developed for a range of grid and customer applications. Battery interconnection requests have been on the rise in recent years with economic factors—namely declining technology costs and availability of Investment tax credits for qualifying energy storage systems—driving the trend.

Again, we see economics driving the ERCOT market as opposed to regulation as is the case in other US deregulated energy markets.

No FERC Order 841.
No problem for energy storage in Texas.

Even though ERCOT is not under the jurisdiction of the Federal Energy Regulatory Commission (FERC) or its Order No. 841 (which requires ISOs to provide more opportunities for electric storage resources to participate in energy, Ancillary Services and capacity markets), ERCOT is making progress toward integrating energy storage as a key resource in its market.

The Public Utility Commission of Texas's Project No. 48023 is open and currently reviewing non-traditional technologies in electric delivery services. Electric storage resources are a key focus of the project.

Here, we have yet another variation on the theme of the Texas energy market's design. Put economics in the driver's seat and watch how it all works out. Unlike other states, Texas isn't passing mandates that require storage to be implemented. Instead, the market is set up to allow the most economically viable resources to participate.

While ERCOT has stated that it "is monitoring the changes being considered and implemented by the other ISOs to help inform its own future processes related to the integration of electric storage resources," perhaps it's the other markets that should be looking to Texas for guidance.[10]

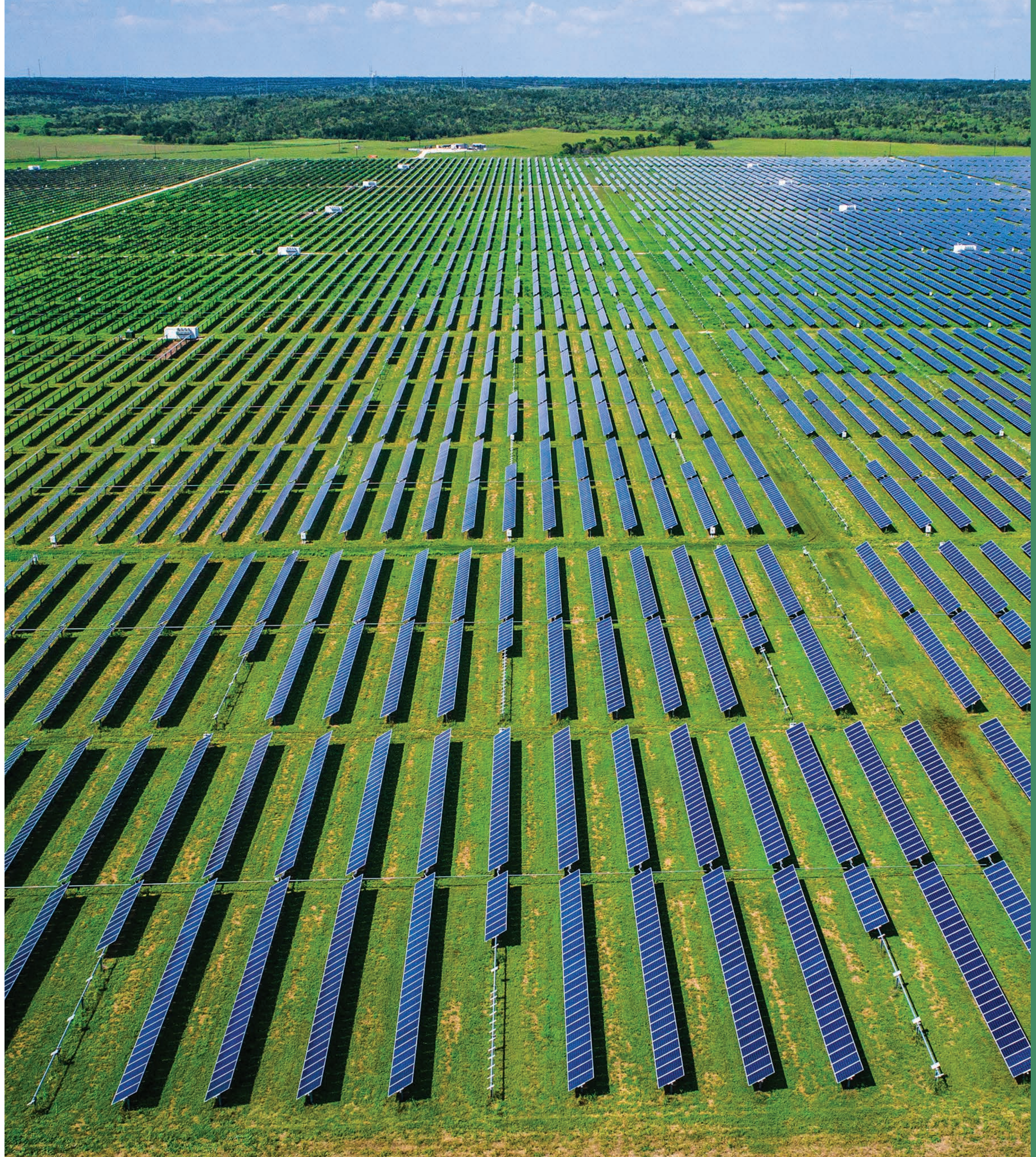
Texas appears poised to be one of the few, if not only, deregulated energy markets in the US that can claim a path to properly valuing renewables and energy storage in its marketplace in 2020.

Demand Response and
the 'New Normal' in Texas

As ERCOT increasingly relies on wind and solar as primary fuel sources, flexible demand-side resources can play a key role in providing grid resilience. The events on both August 13 and 15 of 2019 are proof that demand response (DR) resources in Texas are dependable in times of grid stress.

ERCOT, however, isn't resting on its DR laurels. Electric demand in Texas continues to rise as does consumer desire for behind-the-meter distributed generation, including energy storage. These conditions constitute a new normal in Texas, one that shows no signs of abating in the near future.

In store for 2020 are a few new DR additions, replete with Texas-style incentives, aimed to keep the electricity flowing in times of grid stress.



Demand-Side Management Options in ERCOT

ERCOT maintains day-ahead, real-time energy market, and ancillary service markets. These markets are comprised of participating assets on both the generation and demand-side (behind-the meter).

To maintain grid reliability and help organizations in Texas offset their energy use and spend, ERCOT offers the following demand-side energy management programs:

Demand Response:

Emergency Response Service (ERS) is ERCOT's entry-level demand response program. ERS pays organizations for using less energy when the grid is stressed or when electricity prices are high. There are two types of ERS programs: ERS 10 and ERS 30, which pay businesses for being available to curtail their energy loads within 10 and 30 minutes.

ERS currently has a procurement cap of $50 million per year. However, CPower believes that if ERCOT wants to continue to rely on and grow this program, there will need to be an increase in the funding of ERS. With the growing amount of intermittent renewables on the grid, ERS is more important than ever to fill the gap when the wind isn't blowing and the sun isn't shining. CPower is actively engaged with the PUCT and ERCOT on behalf of our customers in an effort to increase the reward for participation in ERS..

Load Resource (LR): LR is potentially 2-3 times more financially rewarding than other ERCOT programs for businesses who participate. The Load Resource Program is capped at 1400-1750 MW of total procurement. If more than this limit clears the market, then proration will be triggered.

SOP Utility Program: Each utility offering this program has specific goals. The SOP program is very similar to ERS, except it is called only in summer afternoons.

What's new to demand response in Texas in 2020?

ERCOT Contingency Reserve Service (ECRS): Available in 2022, the new ERCS program is very similar to the Load Resource program in that resources must respond within 10 minutes of being dispatched and must continue to sustain their performance for "as long as they have the responsibility to provide this service." ECRS differs from LR in that the new program does NOT have an under-frequency requirement.[11]

Demand Management:

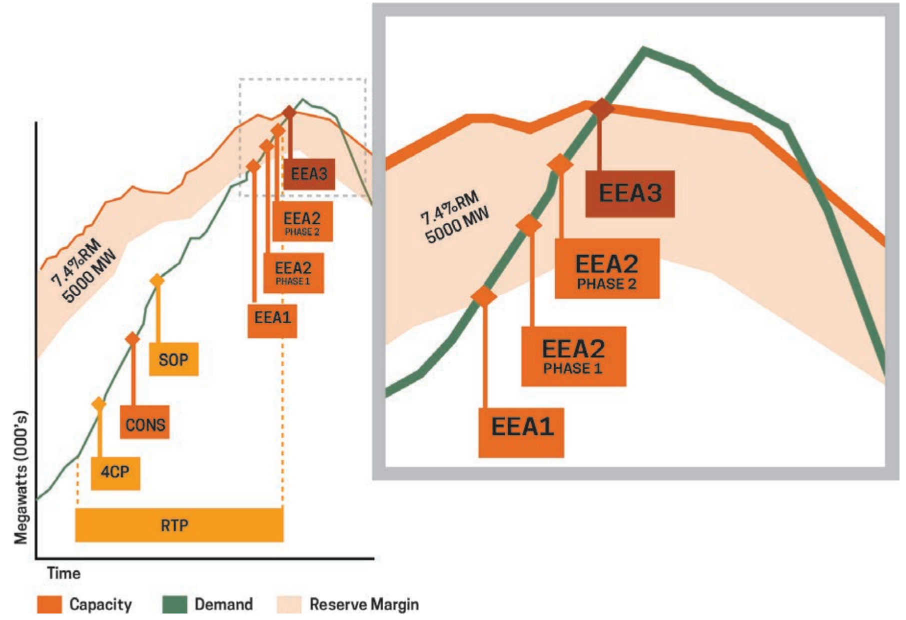
4CP Management: Every month your business is charged a fee—called a peak charge or, more specifically in Texas, a 4CP charge—based on how much electricity an organization consumed during the period when electricity demand on the grid was at its highest.

4CP management involves curtailing energy consumption during periods of peak system load, thereby lowering 4CP value, which in turn reduces 4CP power charges the following year.

What is ERCOT's protocol for dispatching demand-side resources?

As the state's grid operator, ERCOT maintains a sophisticated system of levers and triggers that dispatch increasingly potent demand-side resources designed to help maintain balance when the demand for electricity outpaces the grid's ability to supply it.

Understanding ERCOT's system provides a context to help understand not only how demand-side resources are used in Texas, but also which of the demand response programs might be best for a given organization.



TYPE	RESERVE MARGIN	DESCRIPTION
Conservation Alert	<3,000MW	ERCOT may call upon consumers to take steps to conserve power by reducing consumption.
EEA 1	<2,300 MW	**Texas Electricity Conservation Needed** ERCOT operator's authority to call on available power supplies. ERS 30 can be called at this point.
EEA 2	<1,750 MW	**Conservation Critical; Risk of Rotating Outages** ERCOT escalates to a Power Warning which allows ERCOT operators to dispatch Load Resources providing Responsive Reserve Services as well as ERS 30 & ERS 10.
EEA 3	Rolling Blackouts	**Rolling blackouts to all areas of ERCOT grid** If capacity shortage is not relieved using voluntary and contractual demand response, ERCOT will instruct utilities to rotate power outages to prevent statewide blackouts.

ERCOT's arsenal for grid defense

When the grid is stressed, ERCOT takes the following steps to avoid blackouts across the state:

Real Time Pricing—this relies on basic economics to deter electricity consumption. As demand rises and approaches the reserve margin, prices start to rise. Large consumers monitor the real time price and determine it's more economically sound to stop consuming (and producing in the commercial sector) given the escalating electricity prices.

If demand continues to rise…

4CP--At any given point, there are about 1,500 MW of "peak-chasing" load that can be curtailed by a collection of consumers seeking to lower their 4CP charges the following year. Typically, this load will come off the grid between 3-6pm during the hottest days of the year.

If demand continues to rise…

Utility Demand Response Programs--Utilities (Oncor, CenterPoint, et al.) have roughly 200 MW that can be called for a three-hour dispatch.

If demand continues to rise…

Voluntary Curtailments--when demand infringes the 3,000 MW mark of the reserve margin, ERCOT issues a series of public address announcements urging consumers to voluntarily shed their load.

If demand continues to rise…

Energy Emergency Alert 1 (EEA1)--ERS 30 demand response resources are called.

If demand continues to rise…

Energy Emergency Alert 2 (EEA2)--ERS 30, ERS 10, and Load Resources are called.

If demand continues to rise…

Rolling blackouts--ERCOT will instruct utilities to rotate power outages in an effort to avoid statewide blackouts.

Why Load Resource was VERY rewarding in 2019

The year Load Resource had in 2019 embodies how economics drive the Texas energy market, keeping the grid reliable, demand response participants happy, and electricity rates relatively low for ratepayers.

Load Resource has consistently been ERCOT's most rewarding demand response program. In 2019, the program paid extremely well and participants were never called to curtail their loads. [12]

As we've discussed, dispatching Load Resource is ERCOT's last line of defense before initiating rolling blackouts. In the events on August 13th and 15th, grid balance was restored before Load Resources were needed. Still, Load Resource participants earned revenue 1) for being available to curtail and 2) because of the spike in real-time pricing that reached $9,000/MWh.

What kind of year 2020 will be for Load Resource is a difficult prediction. Electric demand is rising in Texas and ERCOT has taken measures to keep its grid reliable. The reserve margin is growing and a new demand response program will eventually be added to the arsenal. But if we look at the last five years, Load Resource has been called a grand total of zero times. All the while, participants have earned significant revenue.

If you believe the past is as good an indicator as any to judge the future (and we do), then it looks like 2020 will be another strong year for Load Resource.

Demand Response vs 4CP Management in Texas

Organizations trying to decide whether 4CP management or demand response participation is the better demand-side pursuit should be aware that a single test day in the ERS program (15-30 minutes annually) is often more lucrative than chasing the four coincidental peaks in an attempt to reduce 4CP charges the following year.

Additionally, 4CP events are longer than DR events.

ERCOT predicts the reserve margin will rise a little in 2020, a lot in 2021.

In its December Capacity, Demand, and Reserves (CDR) Report, ERCOT forecasted the planning reserve margin for summer 2020 to be 10.6%, a 2% increase from summer 2019.

The reason for the increase stems from the way ERCOT calculates the capacity contribution of renewables on the grid. However, the region will continue to see above-normal growth in peak electricity demand, particularly in Far West Texas and along the state's coast where new industrial facilities are under construction.

ERCOT projects a significant increase in the reserve margin in 2021, forecasting 18.2%. This projection assumes that much of the solar and wind resource that is currently under study is approved, built and comes online by 2021. It is unlikely, however, that the renewables under study will come online with the kind of volume that warrants such a substantial rise in the reserve margin.

A more likely scenario is that the ERCOT reserve margin remains tight in 2021, but we will be sure to revisit the issue in next year's installment of this book.

Final Thoughts: The Texas energy market proved itself in 2019 and will be a leader in 2020.

We've touted the design of the Texas energy market as one other deregulated markets in the US should look to as a model for letting economics, not regulatory mandates, determine how participants help the grid maintain reliability.

It's that design that has Texas on the cusp of becoming a nationwide leader in renewable energy and DER integration. While other markets like New York and California are mired in bureaucracy, their markets struggle to value and allow popular resources to participate. Texas, on the other hand is humming along, content that economics will determine which are the best resources to participate in the ERCOT market.

It's working. And now, the eyes of the energy nation are looking to the Lone Star State for cues on how to evolve an energy market in this transformative time.

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Joe has responsibility for CPower's demand-side energy management offerings in Texas. He has more than 27 years of management experience leading sales teams for Fortune 100 companies and electric utilities. During his tenure with Motorola, Mr. Hayden provided solutions for investor-owned utilities such as Xcel Energy, Oncor, Entergy, TECO, AEP, and LCRA.

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Mike has extensive experience in analyzing and developing market rules in multiple energy markets across North America. His career has focused on advocating for demand side resources as a reliable low-cost option to traditional generation. Mike has worked with both electric grid operators and utilities to maximize DR enrollment in their programs.

MISO

At the stroke of midnight on December 19, 2003, the Midcontinent Independent System Operator (MISO) took its place among the largest power grid operators in the world when it integrated 10 transmission companies and 33 new market participants from Mississippi, Louisiana, Arkansas, Texas, and Missouri.

Covering a vast area from Manitoba in central Canada to the Gulf of Mexico in southern Louisiana, MISO all but bisects the United States. For nearly two decades MISO has worked to stay true to the approach it has taken since it was approved as the nation's first RTO in 2001

Be reliable. Be efficient. Provide value to customers by avoiding the mess other markets have brought on themselves with ambitious goals and staunch regulations.

You might not see the previous sentence anywhere on the MISO's website or in its mission statement. But

consider how CEO John Bear explained the region's approach in a 2017 interview, "[We have] taken a bunch of small, regional utilities and given them a super-regional utility that requires less investment."

Bear asserted in the same interview that MISO is "driven by enhanced reliability, more efficient use of the region's existing transmission and generation assets, and a reduced need for the addition of new assets."

MISO's do-more-with-what-we-have approach to market design isn't a rejection of innovation and renewable resource integration. Far from it as we'll see in the next few pages. But for the last 15 years, MISO has operated under the belief that by not having a forward capacity market, by avoiding subsidies of resources, and by empowering utilities they can avoid controversies and headaches other deregulated markets in the US are facing.

Unlike other multi-state energy markets in the US, MISO's individual states drive the bulk of the regulatory policies and control the levers and mechanisms that keep the grid's supply and demand in balance.

The ISO has also made a mission of delivering and demonstrating value to its customers.

What makes MISO different from other organized energy markets?

Electric utilities in MISO have the responsibility of generating, transmitting, and distributing the electricity required to meet retail distribution load. This is unlike the deregulated market model more common in the US, where utilities are required by law to be divested of generation assets.

This vertically integrated structure provides MISO advantages in the eyes of its officials. For one, states have jurisdiction over resource adequacy. This structure differs from other multi-state ISO/RTOs like PJM and New England, where the ISO is responsible for maintaining resource adequacy and must adopt the arduous task of working through each state's public utilities commission to ensure sufficient capacity resources are available to maintain grid reliability.

MISO aims to provide transparency into near and long-term resource requirements, while individual states set resource adequacy requirements for load-serving entities (LSEs) to meet.

The Planning Resource Auction (PRA)

Each spring in advance of the prompt delivery year, MISO administers its Planning Resource Auction (PRA) through which load serving entities must procure enough capacity to meet their resource adequacy obligations.

Unlike PJM or New England, MISO's PRA does not have a forward auction component through which capacity for a given delivery year is acquired years in advance.

Most LSEs in MISO are utilities which (unlike in other markets) self-supply the capacity resources they need from the generation assets they own. As a result, there isn't much additional capacity that needs to be procured by MISO or the LSEs to hedge against times when electric demand on the grid exceeds its supply.

What makes MISO similar to other markets?

Like other energy markets in the US, MISO recognizes the need to evolve its fuel mix from one that's been traditionally dominated by coal to one that is largely renewable.

Since 2005, when nearly 80% of the region's total energy was generated from coal, MISO has steadily altered its fuel mix to cleaner sources. Today, less than half of the region's total energy comes from coal. [13]

During that same timeframe, wind and solar has steadily grown in popularity, creating a dilemma for MISO that other ISOs and RTOs know all too well.

MISO has a vision for the future. D's are involved. Three of them to be precise.

The Three Ds.

In a March 2019 report titled *Miso Forward: Delivering Reliability and Value in a 3D Future*, MISO introduced its 3 D's: De-marginalization, decentralization, and digitalization. Other deregulated US markets have introduced their version of the Three Ds. Most swap decarbonization for de-marginalization and some prefer deregulation to decentralization, but there are a lot of ways to skin a cat when it comes talking about cost-efficient renewables and passing laws to integrate them onto a grid.

De-marginalization

MISO defines de-marginalization as “the modified set of resources that can provide the next needed, or marginal, increment of energy at zero additional cost or very low costs.” Before you toss this bit of nebulosity in the whatever-that-means file, understand the operative word here is costs. MISO has seen how other US energy markets are evolving to cleaner futures and has a paramount, customer-centric concern. Keep. Costs. Down.

Low costs are a goal for MISO, with low rates for consumers a key piece of the ISO’s value proposition. Low prices, on the other hand, are a circumstance that exacerbate the inherent challenges of evolving a fuel mix.

Over the last several years, low energy costs have played a significant role in the retiring of traditional generation assets, namely coal and nuclear plants that have bowed out of a competitive marketplace. As a result, MISO’s excess capacity beyond planning reserves targets dropped from 14% in 2013 to just 2% in 2018. [14]

With coal and nuclear-fueled generation decreasing at a time when wind and solar resources are rising in popularity, MISO finds itself in a situation other RTOs in the US know well. The intermittency of wind and solar resources creates what MISO calls “resource availability gaps” and the layperson would call *times when demand on the grid exceeds the grid’s ability to supply it because the sun isn’t shining or the wind isn’t blowing*.

Flexible resources that can be dispatched quickly to offset intermittency are the answer. MISO acknowledges as much. The region has pledged to attain a goal of a 50% renewable fuel mix by 2030. To get there, however, the region will have to address the issues of their next D.

Can MISO Decentralize?

For MISO, perhaps *decentralization* may be the most daunting D.

Like other deregulated markets, MISO recognizes a need to move away from central-station power plants to smaller resources that are local, of lower wattage, and sometimes on the demand-side in homes and businesses. Unlike other markets, however, MISO’s version of decentralization will involve dealing with utilities that own their own generation and are accustomed fulfilling 100% their resource adequacy via self supply.

MISO is optimistic and, in their official words, “uniquely positioned to partner with stakeholders to enhance products, services, operations and planning approaches around availability, flexibility, and visibility.”

In a nutshell, the one-way power flow that’s been the traditional model in MISO since its inception will have to evolve to become more bi-directional as distributed energy resources provide electricity to local grids.

Exactly when and how this transformation will take place is not yet known. MISO, to its credit, is examining its options, all the while keeping close ties with its stakeholders to develop a plan for grid evolution that learns from the missteps other more progressive markets have made.

Availability, Flexibility, and Visibility

The future, MISO rightly believes, will one day be decided by external factors like wind and sun, which power wind and solar resources that aren't always available. Unpredictable availability creates a pressing need for resources with inherent flexibility, meaning they can be dispatched quickly in the face of cloudy and/or windless hours.

Every market in the US has been down this road and arrived at the same conclusions. Renewables are intermittent and require flexible resources to offset their inevitable lack of availability. Most markets--particularly early adopters of significant renewable penetrations like California, New York, and New England--are currently dealing with the unintended issues they didn't necessarily see coming when they set out to evolve their fuel mixes from fossil-based to renewable sources.

MISO, on the other hand, believes visibility is the key to avoiding the pitfalls that have ensnared other markets working toward a cleaner future. Visibility, in this case, means the ability to see and coordinate 1) energy resources that supply the grid, 2) demand on the grid itself, and 3) planning for the future.

The key, in MISO's eyes, to maintaining a reliable grid lies in the region's members being able to *see* the resources that are on their local transmission and/or distribution systems.

MISO concedes that access to these systems must be "non-discriminatory, reflect costs, and support optimal grid development through sufficient visibility both vertically (up and down the infrastructure) and horizontally (in collaboration with regional seams partners.)"[15]

By being transparent (a synonymic offshoot of visible) in its approach to addressing future needs, MISO hopes to earn the trust of its members during what will likely be a challenging adjustment of decentralization.

Can what got MISO to the present carry it to the future?

MISO is counting on it. Executive Vice President Richard Doying has publicly stated that it is the ongoing collaboration across sectors including a diverse footprint of end-use customers, natural resources, utilities, and customers that has helped the ISO "achieve 99.99% system reliability and efficient market outcomes."[16]

It is precisely that collaboration, MISO believes, that will help the ISO carry out its vision for the future.

So when will the future arrive for MISO?

Like other energy markets, MISO has a vision for where it wants to go. From here, it will take state action to map out and enforce that future.

While other US energy markets are fighting their way through the regulatory stage of their push to the future, MISO is still very much in exploratory mode. They've presented in broad strokes a vision for their grid's evolution and are working with their members and states to outline a plan that could one day map toward that vision.

Demand Response in MISO

Remember how utilities in MISO largely self supply their resource needs? That means that MISOs capacity market requirements are already met or exceeded through utility controlled supplies which means low prices for any remaining needs. Many utilities include demand response in their supply portfolios. These supplies are procured through state commission approved utility tariffs.

Not that grid stress has been a problem for MISO. In the last several years, the region has called just less than a handful of mandatory demand response events during which the grid was threatened due to either high electricity prices or demand for electricity exceeding the grid's ability to supply it.

MISO likes it that way. So do its customers. But given their stated desire to move toward a renewable based fuel mix, it seems logical that MISO will reach the conclusion concerning flexible resources that other US markets are starting to realize. Demand response packaged with other resources (particularly energy storage) provides the fast-acting flexibility evolving grids need to offset intermittency from wind and solar.

Recent changes to demand response in MISO

MISO's demand response programs traditionally required seasonal participation, particularly in the summer when the grid experienced its heaviest demand. A cold snap in January 2018 made MISO realize it needed to procure year-round emergency resources.

Like PJM, who realized in 2014's Polar Vortex that its winter DR needed bolstering, MISO almost found out the hard way that it needed year-round availability from its DR resources. For several hours as grid conditions worsened, demand response capacity fell hundreds of megawatts short of what had been scheduled to be provided.

MISO avoided blackouts, but realized a need for change. On February 19, 2019, the Federal Energy Regulatory Commission (FERC) accepted MISO's submitted tariff revisions, paving the way for demand response capacity procured through the Planning Resource Auction to be available year-round as opposed to during the summer only as was previously the case.[17]

Available Demand Response Programs in MISO

Demand response is among the most cost-effective and practical of all demand-side, flexible resources. The capacity DR provides in an emergency situation can be dispatched as fast as a participating organization can be notified and then curtail its pledged load. The key to effectively using DR to balance the grid at the ISO and/or utility level lies in properly incentivizing capacity in the marketplace.

The combination of utility self-supply of capacity with utility-managed demand response programs has created challenges for regulators to determine how much demand response can be provided and at what cost. State regulators are improving their understanding of the value that demand response can provide relative the large investments needed for large central stations and even renewables.

Demand Response Types and Their Participation in MISO Wholesale Market Products

Types and Products	Five Minute Dispatchable Energy	Regulating Reserve	Spinning Reserve	Supplemental Reserve	Capacity
DRR Type I	Y (Only Single Value Load Reduction)	N	Y	Y	Y
DRR Type II	Y (Range of Load Reduction)	Y	Y	Y	Y
EDR-JMR	N (Only Emergency Load Reduction)	N	N	N	Y
EDR-non-LMR	N (Only Emergency Load Reduction)	N	N	N	N
LMR-BTMG	N (Only Emergency Load Reduction)	N	N	N	Y
LMR-DR	N (Only Emergency Load Reduction)	N	N	N	Y

Valuing Distributed Energy Resources (DERs)

Every energy market in the US, except MISO, is struggling to properly value DERs (including DG) in their marketplaces. MISO isn't yet struggling because they haven't gotten far enough in the evolution of their grid to warrant a need to stimulate their market.

Energy in MISO's regions is inexpensive. Customers, especially the heavy industrial loads in the south, appreciate the low prices. MISO acknowledges the importance DERs will play in its grid of the future. But in 2020 there doesn't seem to be anything on the horizon that indicates DER capacity will be valued in MISO's market.

Final Thoughts

One constant about the future is that it never goes away. MISO can only stay in exploratory mode for so long. Eventually, this region that has enjoyed exceptionally low energy prices while maintaining stellar grid reliability will have to deal with a changing resource mix and increasing penetration of DERs.

2020 will not be the year MISO introduces drastic changes to its grid or market. The region has, however, positioned itself just right to afford the slow evolution it desires. So long as the grid stays reliable, the energy stays affordable, and the customers stay happy, MISO can sit back and learn from other markets' successes and mistakes then deciding for itself how to best march into the future.

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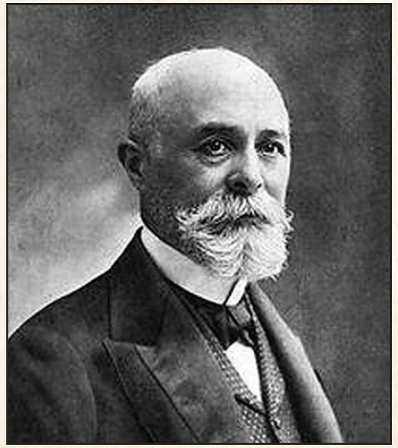
SOLAR



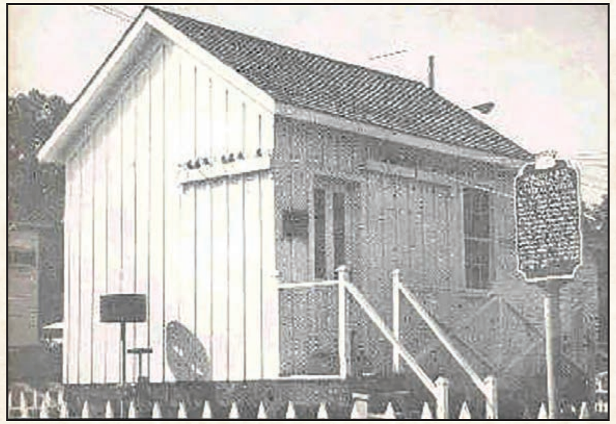
Charles Fritts (1850-1903) was an American inventor credited with created the first working solar cells from selenium in 1883.

In 1884, Fritts installed the first solar panels on a New York City rooftop.

Fritts had dreams of his solar cells competing with Edison's coal-fired power plants. His cells, however, were less than one percent efficient at converting sunlight to electricity and thus not very practical.

With more than 1.7million panels spread across more than 13 square kilometers in Kern and Los Angeles, California, Solar Star is currently the largest solar farm in the US.

HYDRO-ELECTRIC



Built in 1882 in Appleton, Wisconsin on the Fox River, Vulcan Street Plant was the first Edison hydroelectric central station.

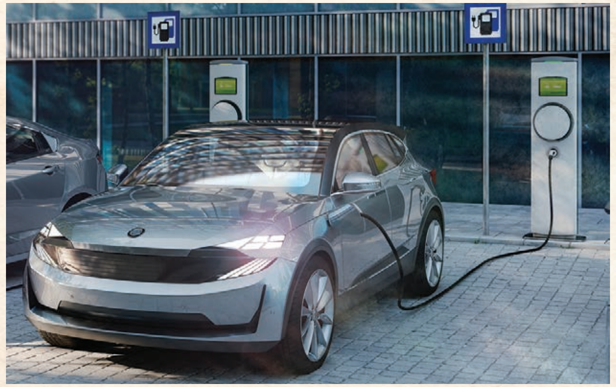
The power output was at about 12.5 kW. 7 years later, in1889, the total number of hydroelectric power plant solely in the US had reached 200.

Today, the largest hydroelectric plant in the US is at Grand Coulee Dam. It has a capacity of about 6,808 MW and generates, on average, 21 billion kWh per year.

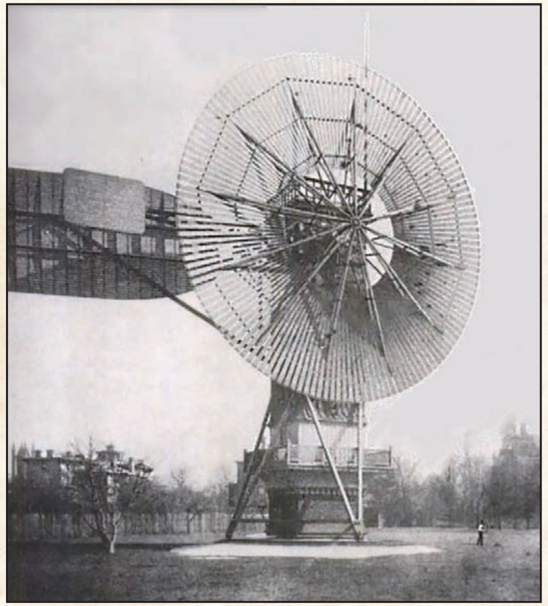
ELECTRICITY

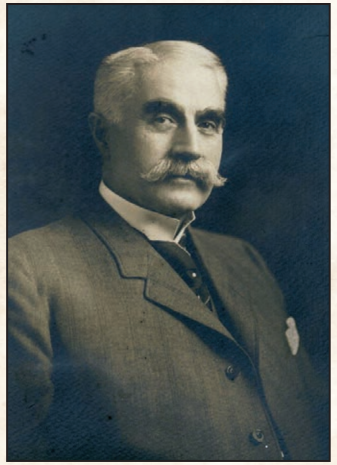
British-born Samuel Insull (1859-1938) was one of the most important American business magnates of the 20th century, widely considered the father of the modern electric utility and regulated monopoly. He spent the first 20 years of his career as Thomas Edison's personal secretary and would go on to become one of the richest men in the US.

Pictured: Chicago Edison's 5 MW steam turbine at Fisk Street station in 1907. Insull convinced GE to manufacture the turbine-generator unit in 1902. By 1903 it was put into operation and the business of centralized electrical generation in the US would never be the same.



WIND





In 1888, the first known US wind turbine created for electricity production was built by inventor Charles Brush to provide electricity for his mansion in Ohio.

Southern California's Alta Wind Energy Centre, is the largest wind farm in the US.

According to the National Renewable Energy Laboratory, the contiguous United States has the potential for 10,459 GW of onshore wind power. The capacity could generate 37 petawatt-hours (PW·h) annually, an amount nine times larger than current total U.S. electricity consumption.

The New York City blackout of 1977 led to arson and looting in several of the city's neighborhoods. The blackout cost the city an estimated $300 million ($1.2 billion today) and was a catalyst for developing demand response as a way to balance the grid when demand for electricity exceeds its supply.

NEW ENGLAND

On November 18, 2019, ISO-NE CEO Gordon van Welie received a letter from a group of ratepayers urging New England to keep the region's climate and environmental goals top-of-mind as the ISO works to ensure fuel security.

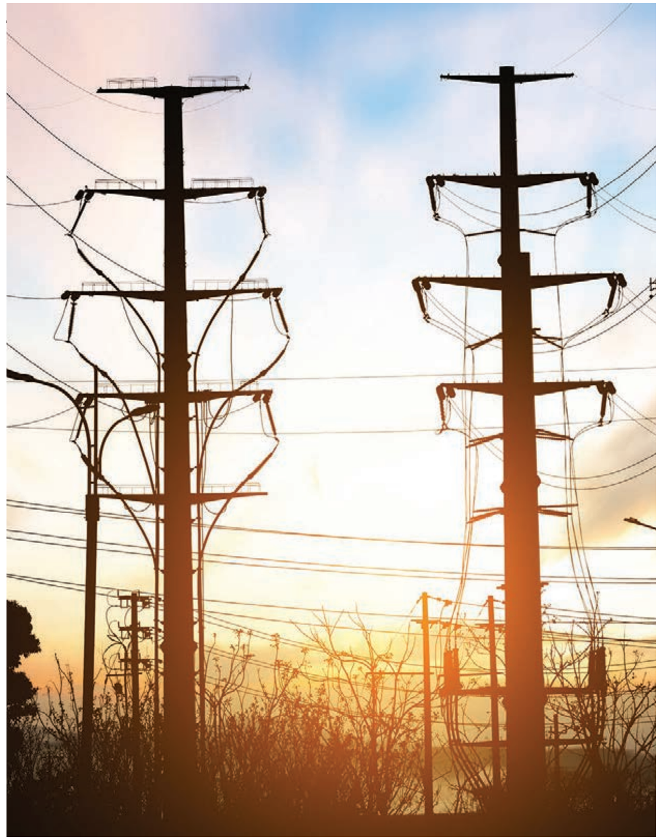
The letter's signatories charged ISO-NE had recently ventured down a path of market redesign that diverted from not only the desires of New England residents, but also from state policies.

Specifically, the letter asserted, "Instead of continuing this engagement with stakeholders, in recent years ISO-NE has charted its own path forward and pursued unpopular initiatives like CASPR and the Inventoried Energy Program.

"Now, ISO-NE is pursuing as its top priority a new energy security improvements fuel-security proposal that again appears to ignore the reliability and other benefits of clean energy, and further delays to market reforms that recognize and facilitate state public policies to grow clean energy and address climate change."

If the exactness of the letter's language and precision of its accusations sound as if the citizen-authors hired a ringer to pen their grievances, that's because they may very well have. The letter was signed by eight democratic senators from New England, including US presidential candidates Elizabeth Warren and Bernie Sanders.

It is an election year, after all. That means the complex challenge of evolving a grid and energy market into the future won't escape the scrutiny of political debate. But if we can remove our ideological hats for a moment and examine the New England energy market with an objective eye, we can begin to see ISO-NE's recent efforts to improve market design and ensure fuel security have followed a logical progression of trial and error rather than a unilateral charge ripe for political grandstanding.



Fuel security remains New England's biggest concern.

In its 2019 State of the Grid Report, ISO-NE revealed that the grid's most pressing vulnerability is energy security. The ISO cited its "inadequate fuel delivery infrastructure" as the reason electricity demand during extended winters may go unmet.

As we highlighted in last year's version of this book, New England's winter fuel security is an energy supply problem not a capacity shortfall problem. ISO-NE has stated that as wind and solar sources increasingly contribute to the grid's fuel mix along with more just-in-time fuel, the supply problem that has created a winter fuel shortage could become a year-round issue for New England.

ISO-NE believes market design is the answer.

ISO-NE market redesign proposal: incentivize generators

ISO-NE's goal with redesigning its market is to compensate resources that help the system maintain its energy inventory.

Consider natural gas generators. Currently, the economics in New England are such that natural gas generators do not kee inventory for multiple days. Rather, they offer their capacity into the day-ahead market. Why? Economics. The generators feel it's in their best financial interest to take positions in the capacity market and reap the reward from emergency conditions as opposed to what they would earn in the energy market.

Normally, that wouldn't be a problem. That's how the market is currently designed, after all. But remember, New England's winter fuel problem is supply-related. The region has plenty of capacity. It needs more supply, particularly during extremely cold conditions.

OK, says ISO-NE, let's introduce a proposal to redesign the market on the energy side and incentivize natural gas generators to keep more inventory that can be delivered in the winter, thereby alleviating the fuel security risk.

Problem solved. Right? Well...theoretically yes. But by altering the market on the energy side to incentivize generation, ISO-NE may unwittingly affect its capacity market in a negative way.

Unintended consequences for the New England capacity market

Natural gas generators typically take large positions in the capacity market, offering at a specific price that, when accepted, tends to establish capacity's clearing price in New England's forward capacity market.

If natural gas is incentivized in the energy market, as ISO-NE's market redesign proposal intends, natural gas generators may become price takers in the capacity market. They no longer would have an interest in taking a large capacity position in the market. As a result, the price of capacity could fall from year to year.

As more renewables come online and ISO-NE looks to integrate more distributed energy resources onto its grid, a depressed capacity market poses problems. ISO-NE has proposals in the works to address these concerns.

ISO-NE's Market Proposals.

In April 2019, ISO-NE introduced three ideas to build on New England's competitive wholesale electricity structure. The goal is three-pronged:[18]

Strengthen generation owners' financial incentives to undertake more robust supply arrangements.

Reward resource's flexibility to mitigate energy supply uncertainties that take place throughout the day.

Efficiently allocate electricity production across multiple days from resources that have limited (non-just-in-time) energy sources.

To accomplish these goals, ISO-NE introduced three new components that are currently under review. For commercial and industrial organizations looking to optimize their demand-side energy resources, these proposals are worth keeping an eye on because they by and large affect the region's capacity market in what ISO-NE hopes is a positive way.

The Multi-day ahead market

This would be a voluntary market for forward energy transactions extending the current (single) day-ahead market several days in advance of the operating day, with daily offers rewarded with the price at which they clear on that day.

By extending the day-ahead market to several days, ISO-NE seeks to enable suppliers to refine their energy positions (adjusting due to changes in fuel supplies, costs, and delivery capabilities) prior to the delivery day. The ISO figures it can optimize the region's limited energy supplies and avoid scarcity pricing conditions during extreme cold weather when the region might otherwise be forced to turn to costly, out-of-market resources.

While the multi-day ahead market is supply-side in nature, it may have a demand-side impact if it succeeds in thwarting the exceptionally high energy prices that trigger a demand response event. Without the high prices, a demand response event is less likely to occur.

But that's not necessarily bad news for DR participants. Although they are less likely to be dispatched to curtail their loads, DR participants will still be required to comply with a seasonal test for which they are paid.

New Ancillary Services in the Day-Ahead Markets

Most energy resources in New England operate during hours of the day for which they receive an energy supply award in the day ahead market. But what happens when one of those cleared day-ahead resources is unable to operate?

ISO-NE calls these instances "energy gaps" in the operating plan. The resources that were incentivized to run but can't must be replaced by resources that were *not* incentivized to run.

The way the region's energy market is currently structured, it simply isn't profitable to procure fuel in the case of an energy gap. With new ancillary services in the day-ahead market, ISO-NE hopes to remedy the situation by rewarding flexible resources that can fill the gaps when emergency conditions arise.

Exactly how these new services will be rewarded is a detail the ISO is ironing out. ISO-NE has suggested, however, that these new ancillary obligations should be settled like a call option on real-time energy.

Seasonal Forward Market

The third component ISO-NE has proposed is a voluntary forward auction with the goal of facilitating investment in the supplementary energy supply arrangement several months in advance of each season. The aim here is to ensure there is adequate energy supply in the winter.

ISO-NE has some work to do on this front and admits as much. They are exploring a revamp of the existing Forward Reserve Market so that it essentially becomes a forward market for the new ancillary services we previously discussed and may be transacted in the day-ahead market.

Valuing Resources in New England

Compared with other deregulated energy markets in the US, New England is a leader when it comes to valuing resources in its marketplace. That's because, for one, the market is actually trying, having recently proposed market redesign legislation to FERC that was approved.

But that doesn't mean it's all gravy and smooth sailing.

Through trial and error, the New England energy market is working its way toward viable market mechanisms that both accommodate increasingly popular resources, particularly renewables, and help the grid maintain reliability. All the while, other regions struggling to value resources in their markets are watching, hoping to borrow successful measures and learn from missteps.

CASPR's first year

The first Competitive Auction for Sponsored Policy Resources (CASPR) took place in February 2019 (for the power year 2022/23), making ISO-NE the first grid operator in North America to implement a market-based mechanism to accommodate sponsored energy resources.

CASPR was created to prevent subsidized resources covered by tax credits or state incentives from depressing prices in the forward capacity auctions.

Beginning in 2019, New England's capacity auction was split into two rounds, essentially creating two auctions.

The first round functions similar to previous capacity auctions, with active and passive demand resources offering specified loads to be curtailed when dispatched by the ISO.

In the auction's second round, retiring resources that secured capacity supply obligations can transfer those obligations to new, subsidized resources that do not have an obligation.

The existing resource — from a retiring fossil fuel plant, for example — can then retire and receive a final payment equal to the difference between the (higher) forward capacity auction clearing price and the (lower) secondary auction clearing price.

How did CASPR fare in 2019?

In short, not as well as ISO-NE had hoped. Why? For one, there simply wasn't a reasonable match between the amount of retiring resources and the amount of renewable resources seeking to enter the market. The ratio was about five to one in favor of renewable sources trying to enter the market versus retiring sources trying to exit.

According to ISO-NE's published results of CASPR, zero capacity supply obligation MW were issued as about 54 MW cleared the auction. [19]

The organizations responsible for these 54 MW are in an interesting position. On the one hand, they have a capacity supply position that will pay them nothing during the first year. Why take the position then?

Now, we come to the interesting part. Because these resources have established themselves as existing capacity resources, they have the opportunity (should they stay in the market) to become price-takers in future Forward Capacity Auctions. That means, in future auctions these resources would clear at the capacity price established in the primary auction not the secondary.

Taking the long view, the first-year resource earning nothing for its obligation has a potentially bright future if, that is, the market redesigns ISO-NE has in the works help the price of capacity in New England avoid depression in the coming years.

Storage. Storage. Storage.

Altogether now...what are the reliability problems an evolving grid with a fuel mix increasingly featuring intermittent, renewable sources like wind and solar facing? Veterans and savvy followers of the New England energy market know the answer to this one knee-jerk. No need to join the chorus. The answer is as easy as picking the Patriots to make the playoffs. [17b]

Resource intermittency is a threat to grid reliability.

Solar PV panels can't generate electricity when the sun isn't shining. Wind turbines don't turn without wind blowing. Simply put, solar and wind sources can suddenly find themselves in adverse conditions during which they can't produce.

So what's a grid to do?

In New England, as in other progressive deregulated markets in the US like California and New York, the answer is energy storage.

FERC ORDER 841: Let storage in

On February 18, 2018, the Federal Energy Regulatory Commission (FERC) issued Order 841, which directed regional grid operators to remove barriers to the participation of electric storage in wholesale markets.

Order 841 seeks to direct regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage. The Order affirms that storage resources must be compensated for all of the services provided and aims to level the playing field for storage with other energy resources.

In working to comply with FERC 841, ISO-NE now faces a host of challenges familiar to other markets seeking to properly value distributed energy resources in the marketplace. New England may not have *the* answer, but they have an answer. 2020 looks to be the year demand-side energy storage makes a significant impact in New England, albeit on the distribution side through utilities.

2020: The Year Storage goes big in New England (thanks to utilities)

New England realizes the value energy storage can provide in offsetting wind and solar resources' intermittency. While ISO-NE is working on market redesigns to allow energy storage resources to participate, electric utilities are jumping into the ring in 2020 with a new program that features energy storage in a starring role.

Beginning in 2020, electric utilities will offer a new demand response program that allows for storage to play a critical role in helping the grid maintain balance when demand for electricity threatens to exceed supply.

Introducing Daily Dispatch Demand Response

To help further reduce peaks on their distribution systems, New England utilities National Grid, Eversource, and Unitil have introduced a new demand response program called Daily Dispatch.

Daily Dispatch is designed to allow energy storage (batteries, thermal storage) to participate because of its ability to be dispatched frequently and quickly in response to rising peaks.

The Daily Dispatch program runs during the summer from June through September. The program is intended to be dispatched (as the name suggests) daily with anywhere from 30-60 events each year during the hot months of July and August. Each event is expected to last about two to three hours.

The new program has an attractive incentive of $200 per kW per summer. Customers' compensation will be based on their average curtailment amount for all the events that are called during the summer.

For example, a customer that curtails an average of 500 kW for each of the Daily Dispatch events would gross a $100,000 for their efforts.

The Daily Dispatch program appears to be an instance where we find electric utilities taking a leadership role in optimizing energy storage to reduce peak load by allowing commercial and industrial organizations to monetize the distributed generation assets in which they have invested.

Since it is at the utility level and not an ISO program, Daily Dispatch needn't rely on the wholesale capacity market to settle payments. Instead, the program can offer a flat per kW rate, thereby allowing participating organizations to monetize their behind-the-meter storage in 2020 as opposed to waiting until ISO-NE establishes its DER valuation policies.

Other Demand Response Programs in New England

ISO-NE also offers the following demand response programs:

Active Demand Capacity Resource

Active Demand Capacity Resource (ADCR) is a demand response program in which participating loads are dispatched when wholesale electricity prices in New England are exceptionally high.

Launched in June 2018 as part of ISO-NE's price-responsive demand construct, ADCR replaced the Real-Time Demand Response Program (RTDR).

Passive [On-Peak] Demand Response

On-Peak Demand Response rewards participating organizations for making permanent load reductions.

Unlike active resources, On-Peak resources are passive, non-dispatchable, and only participate in ISO-NE's Forward Capacity Market. Eligible behind-the-meter resources include solar, fuel cells, cogeneration systems, combined heat and power systems (CHP), and more.

Passive Demand Response participants offer their reduced electricity consumption into the market during both the summer and winter peak hours.

Utility Demand Response Programs

Connected Solutions

National Grid, Eversource, and Unitil are working to lower the amount of total energy our community uses during the summer months when demand for electricity on the grid is at its highest (peak demand).

To help keep their grids healthy and reliable, these utilities now offer the Connected Solutions demand response program that pays businesses to use less energy during peak demand periods.

Peak Demand Management in New England

Every month your business is charged a fee—called a capacity charge or peak charge—based on how much electricity you consumed during the period when electricity demand was at its highest.

Capacity charges can account for up to 30% of an organization's monthly electric bill.

How are peak demand charges assessed?

The New England grid operator, ISO-NE, assesses capacity costs based upon each end user's kW or MW consumed during the peak consumption hour of the entire New England system on an annual basis.

The basic value of capacity, in $/kW month, is determined by an ISO-NE auction process. These values are known three years in advance of any given year. While capacity costs are determined by the ISO, the charges you see on your electricity bill are determined by your supplier. These charges, therefore, vary from supplier to supplier.

Organizations that curtail their energy consumption during periods of peak system load, will lower their capacity value (cap tag) which in turn will reduce power costs.

Final Thoughts:

In 2018, ISO-NE rolled out a new price-responsive demand construct into New England's wholesale electricity marketplace through which resources were dispatched based on economic signals. 2019 proved to be a good year for the construct. There was a single demand response event and participating customers performed well, proving that ISO-NE is on the right track as it aims into the future.

ISO-NE has its work cut out in 2020. They've identified their weaknesses--namely, a winter fuel supply shortage that threatens reliability--and are moving toward redesigning their energy market to address their shortcomings. The ISO has introduced sound ideas for market mechanisms that are currently under review.

In the meantime while ISO-NE reviews and refines its proposals, the region's utilities have provided demand-side opportunities organizations can consider in addition to the host of programs available at the ISO level.

Expect 2020 to be a year for change in New England. Whatever happens, expect some aspect of New England's energy pursuits to be magnified and amplified in a national political debate featuring at least three major candidates from the region, one of whom may very well vie for the Oval Office in November.

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NEW YORK

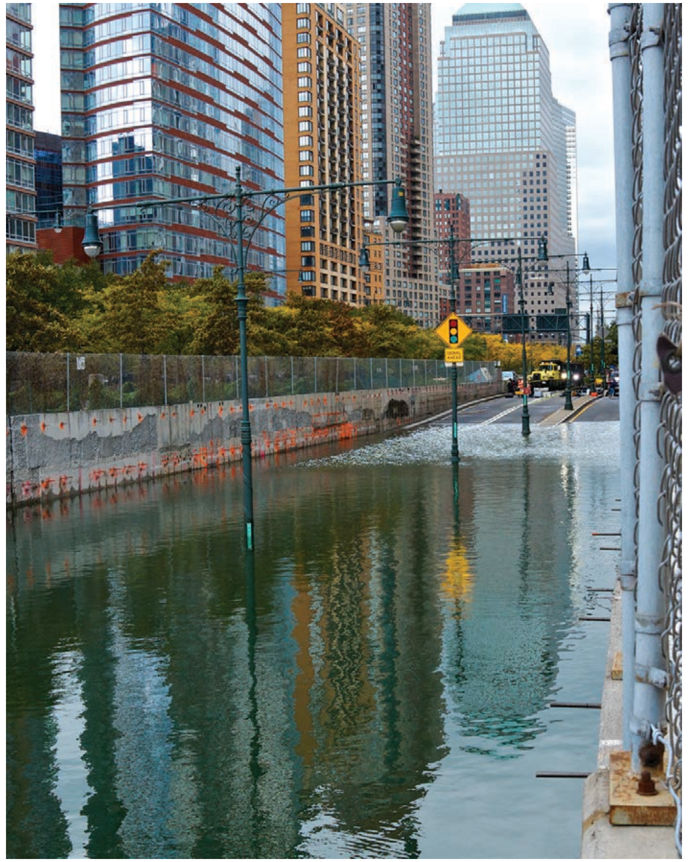
On October 29, 2012, New York Governor Andrew Cuomo took an evening ride around Manhattan. What he saw was harrowing. An apocalypse was taking hold of the city.

The East River had surged above its banks and pushed hundreds of feet west past First Avenue. As he continued his journey through sheets of rain and punishing winds, the governor saw that Manhattan's battery was also under water as was the Brooklyn Battery tunnel, flooded by the relentless surge of the Hudson River.

As he stood above the 9/11 Memorial site and watched its foundation surrender to a deluge from the rising Hudson, Governor Cuomo recalled a movie that reminded him of the surreal sights he was experiencing. Half a decade earlier, former Vice President Al Gore had predicted the city could be flooded by its surrounding waters in his seminal film about the perils of climate change, *An Inconvenient Truth*.

Watching as reality played out just as Gore had prophesied, Governor Cuomo realized the former VP was more of a realist than an alarmist. Extreme weather wasn't a rarity. This was the new normal, a reality that will happen again whether New York is prepared or not.

By the time the waters receded and the winds subsided, Superstorm Sandy had caused over $30 billion in damage to New York State. In the storm's wake, Governor Cuomo made it his mission to modernize New York's energy system, fortifying it to withstand the future and whatever wicked extremes Mother Nature had up her sleeve.



In April 2014, the governor's administration along with the New York State Public Service Commission (PSC) announced the Reforming Energy Vision (REV), a multi-year set of initiatives aimed to modernize New York's aging grid, control energy prices to benefit ratepayers, and thwart the threat of climate change.

Six years later, the REV remains a significant driver of the New York energy market.

Has the REV helped or hurt the New York Energy Market?

Here's a question that could start a food fight in a cafeteria filled with the right mix of New York energy insiders. Let's examine both sides.

The REV certainly has made the Empire State one of the most progressive in the US when it comes to promoting and pursuing clean and renewable energy.

Among the REV's clean energy and climate goals, codified into law in the Climate Leadership and Communities Protection Act in June, 2019:

Among the REV's clean energy and climate goals:

- 85% reduction in greenhouse gas emissions by 2050
- 100% clean energy by 2040
- 9 GW of offshore wind energy by 2035
- 6 GW of distributed solar by 2025
- 3 GW of energy storage by 2030

Proponents of the REV say that it is largely because of these goals that New York has attracted many of the nation's leading energy technology companies, all competing in a healthy market bolstered with effective demand-side energy management options.

Theoretically yes, say the skeptics, who like to quip that for a deregulated energy market New York sure knows how to stymie progress with government regulations. It's been six years since the REV was announced,[20] and detractors think the state could be a lot closer to its lofty energy goals if the market were free to operate without being handcuffed by regulation.

So maybe the more appropriate question to ask is whether regulation helps or hurts the parallel evolution of New York's grid and energy market. Perhaps, as we'll learn in the next few pages, the answer is a little of both.

NYISO's Position on the Future of NY's Energy Markets: Time to Evolve

In May 2019, the New York Independent System Operator (NYISO) published a report titled *Reliability and Market Considerations for a Grid in Transition* that outlined the need for New York's competitive energy markets to evolve as the grid transitions in pursuit of the REV's goals.

In NYISO's words, "New York's power system is facing significant change over the next decade as policymakers promote renewable and storage resources to decarbonize the power sector. The NYSO must prepare its operations and markets to inform and guide this transition."[21]

NYISO's primary mission is the same as all grid operators in the US. Maintain the grid's reliability.

What is the biggest challenge NYISO sees in maintaining that reliability with the steady rise of a fuel mix powered by renewable sources wind and solar? It's the same challenge every other evolving energy grid in the US is facing. Intermittency. Wind turbines only generate electricity when the wind is blowing. Solar PV when the sun is shining. Weather is unpredictable. Unpredictability is a grid operator's arch nemesis.

So what's the solution? (If you've read any of the other sections in this book, you already know the answer.) Flexible resources. Again, in NYISO's words, "As the penetration of those [solar and wind] technologies increases, the grid will need responsive and flexible resources that provide operating reserves to address expected and unexpected changes in net load."

Energy storage, as we'll explore in the next few pages, may be the key to New York's flexible resources being successful in offsetting the inherent intermittency of wind and solar.

Energy Storage in New York: opportunity in the wake of legislation

When it comes to energy storage in New York, you can make the argument that legislation and regulation have, in fact, created opportunities for the resource to grow in popularity. If we look at the landmark milestones of just the last two years, we can see why.

In February 2018, the Federal Energy Regulatory Commission (FERC) issued Order 841, directing regional grid operators to remove barriers to the participation of electric storage in wholesale markets.

Later that year, Governor Cuomo announced a goal that New York would procure what would be a nation-leading 1,500 MW of energy storage by 2025. On the heels of that announcement, the New York State Department of Public Service (DPS) developed the New York State Energy Roadmap, which identified the most promising near-term policies, regulations, and initiatives needed to realize the governor's 2025 storage target, leading to an even loftier 2030 target.

In December 2018, the New York Public Service Commission issued an order establishing an energy storage goal and deployment policy. New York was off and running in pursuit of a 3,000 MW energy storage goal by 2030.

On April 25, 2019, the New York State Energy Research & Development Authority (NYSERDA) filed an approved plan with the PSC that outlines an incentive structure for organizations seeking to install energy storage at their facilities. NYSERDSA's incentives are so attractive they warrant and will receive their own section in this book.

But first, the bad news for New York city and energy storage.

How regulation has halted storage's rise:

It's estimated that the energy storage industry could employ 30,000 New Yorkers by the year 2030.[22] Considering demand for the resource in New York City alone could lead to thousands of commercial buildings lining up for energy storage installation, the employment predictions are reasonable.

So what's the hold up?

Turns out that while some regulations can promote energy storage growth, others can halt it at the gates. In New York City's case, fire codes have been the culprits impeding energy storage's growth, much to the chagrin of the consumers who want the resource and the organizations that want to sell it to them.

New York City has long-been considered a fertile hotbed for energy storage with plenty of commercial buildings that would love to take advantage of the financial benefits energy storage systems provide. The city's Fire Department, however, is worried that the Big Apple might have too much heat in its bed of storage desire. New York City is a densely populated area and energy storage systems, particularly those using lithium-ion batteries, have a history of igniting into flames.

From the City of New York:

> "Lithium-ion batteries are subject to thermal runaway, which occurs when the heat generated by a malfunctioning energy cell or module causes others to fail, potentially generating intense fires and fires that reignite after being extinguished."[23]

They're right. The ratio of discarded lithium-ion batteries to five-alarm fires in New York has been infinitely too high for anyone's comfort. The Fire Department acknowledges that lead-acid batteries, not lithium-ion, are most common in stationary storage battery systems typically used in office and other commercial buildings. Still, the NYFD hasn't been interested in taking chances, hence the regulation that has locked out energy storage systems from entering the city en masse, making New York one of the most restrictive markets in the US for energy storage projects.

The ultra-stringent regulation concerning storage systems and fire codes in NYC is changing in 2020.

Coming in 2020: National Fire Protection Association Standards

This year, the National Fire Protection Association is expected to release the final draft of NFPA 855—Standard for the Installation of Stationary Energy Storage Systems. The regulation is expected to establish "requirements based on the technology used in ESS [energy storage systems], the setting where the technology is being installed, the size and separation of ESS installations, and the fire suppression and control systems that are in place."[24]

The standard has been in development since 2016 and has incorporated more than 600 public inputs. Parties on all sides feel NFPA 855 is a positive step toward the future of energy storage in New York, believing the regulation will help facilitate permitting and streamline installation—all to the benefit of commerce and the pursuit of New York's energy goals.

NYSERDA'S Energy Storage Incentives

To help the Empire State achieve a cleaner energy future, NYSERDA is currently offering significant incentives to promote energy storage integration onto the state's energy grid.

To qualify for NYSERDA's Retail Energy Storage Incentive, an organization's system must:

- Be sized up to 5 megawatts (MW) of alternating current (AC) power
- Be new, permanent, and stationary
- Be located in New York State
- Use thermal, chemical, or mechanical commercially-available technology primarily operated for electric load management or shifting on-site renewable generation to more beneficial time periods
- Provide value to a customer under an investor-owned utility rate, including delivery charges or New York State's value of distributed energy resources (VDER) or participating in utility demand response programs
- Interconnect either behind a customer's electric meter or directly into the distribution system

Organizations that take advantage of these incentives are required to participate in either the VDER tariffs (where compensation is based solely upon electricity exported back to the grid) or in one or more demand response (DR) programs, which pay participants to help the grid by reducing electrical load when demand for electricity exceeds supply or electricity prices are high.

Like other deregulated energy markets in the US, New York has recognized the value of pairing energy storage with demand response. (Hence the Bullet #4 in the requirements above.) To stimulate investment in energy storage, the state is offering a carrot (the incentives) and in return is asking for a favor, support the grid when it's in need of help.

Here's an example of how an organization can save money with NYSERDA's energy storage incentive and the SC-7 tariff demand charge reduction while earning money with demand response:

1 MW (4MWh) storage installed cost:	**$3,000,000.**
NYSERDA storage incentive	**-$1,000,000.**
Estimated tax savings (depreciation)	**-$750,000.**
Net purchase price	**$1,250,000.**

Energy bill savings (Annually)	**+$11,000.**
Demand bill savings (Annually)	**+$105,000.**
Demand response savings (Annually)	**+$34,000.***
Total annual benefits	**$150,000.**

Simple payback 8.3 years

These values are estimates. Actual values will vary depending on a given organization's demand-side energy management. DR values are based on forecasts only. Actual rates may differ based upon ICAP auction clearing prices.

Valuing Capacity Resources in New York

Part of the challenge of evolving an energy market to support a grid whose fuel mix is shifting from fossil fuels to renewables involves properly valuing capacity resources that are only available at certain times of the day.

For the past several years, NYISO and various stakeholders have debated how much capacity value should be assigned to a resource that can only provide for two, four, six, eight, ten, or twelve hours of a given day compared with, say, coal-fired resources which are fully available 24/7 (give or take scheduled outages and such).

Last year, the parties arrived at a capacity valuation proposal that was submitted to FERC and approved on January 23, 2020. NYISO proposed a new aggregation participation model whereby an aggregator may combine individual facilities (including DERs and load curtailment) as a single aggregation that can participate in NYISO's Installed Capacity (ICAP), energy, and ancillary services markets.[25]

If the future in New York is distributed resources and renewables, properly valuing them in the wholesale electricity marketplace while allowing dual participation in retail programs or tariffs is paramount to ensuring sound economics inspire fair participation and permit New York's evolving grid to remain reliable.

Carbon Pricing in New York: a hot topic, still up in the air

Passed in June 2019, the Climate Leadership and Community Protection Act (CLCPA) established for New York one of the most aggressive carbon reduction goals in the nation, calling for the state's electric sector to reach zero emissions by 2040 and for the state to be carbon-neutral by 2050.

Exactly how New York will reach this mandated goal has not yet been decided. NYISO CEO Rich Dewey has let his opinion be known on the matter, publicly stating that a price on carbon would be the most effective way to achieve New York's goals.

NYISO currently has several studies and assessments in the works for 2020, including the Congestion Assessment and Resource Integration Study (CARIS), that aim to inform the policymaking process.

2020 does not appear to be the year New York will implement a carbon pricing policy, however. Instead, the year will likely involve more analysis on the subject.

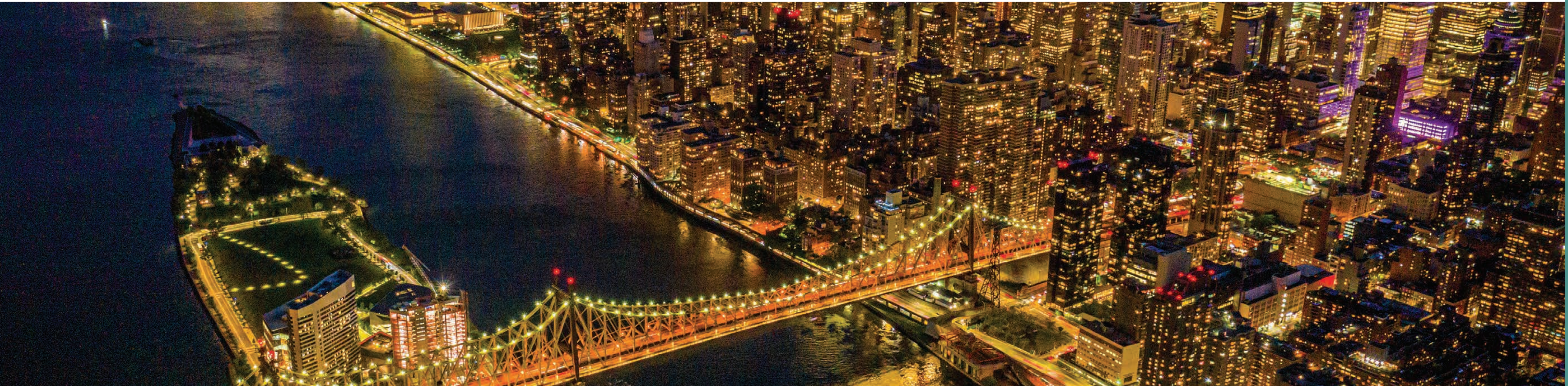
Capacity Prices in New York

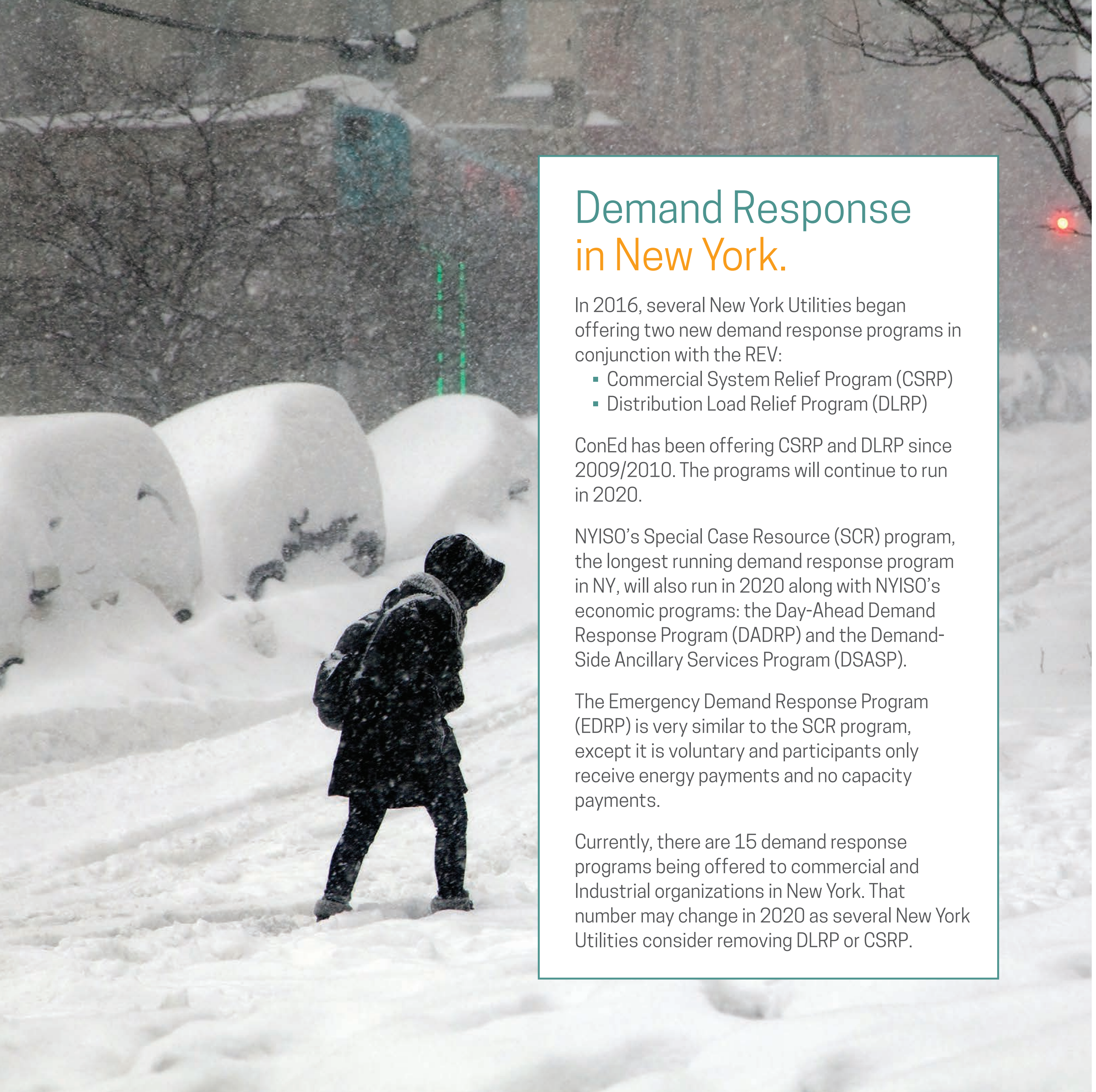
When it comes to capacity prices in New York state, the story changes depending on the geographic region. As was the case in 2019, capacity prices are low right now in upstate New York but increase through the Lower Hudson Valley toward New York City due to transmission constraints.

The announced retirement of Indian Point nuclear facility scheduled for 2020 and 2021 leaves New York with 2,000 MW to be replaced just outside of New York City.

NYISO points to new natural gas generation and other renewable generation scheduled to come online as reasons for Indian Point's retirement. Still, capacity prices in New York City heading into summer last year were comparatively high compared with the rest of the state. The same is true for 2020.

That means organizations in New York City, where capacity prices are higher than the rest of the state, find themselves in a position to take advantage of the many demand response programs New York offers at both the NYISO and utility level.





Demand Response in New York.

In 2016, several New York Utilities began offering two new demand response programs in conjunction with the REV:

- Commercial System Relief Program (CSRP)
- Distribution Load Relief Program (DLRP)

ConEd has been offering CSRP and DLRP since 2009/2010. The programs will continue to run in 2020.

NYISO's Special Case Resource (SCR) program, the longest running demand response program in NY, will also run in 2020 along with NYISO's economic programs: the Day-Ahead Demand Response Program (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

The Emergency Demand Response Program (EDRP) is very similar to the SCR program, except it is voluntary and participants only receive energy payments and no capacity payments.

Currently, there are 15 demand response programs being offered to commercial and Industrial organizations in New York. That number may change in 2020 as several New York Utilities consider removing DLRP or CSRP.

Natural Gas Demand Response.

Con Ed is poised to continue leading New York utilities' push for demand response.

Building on its 20-year experience administering DR programs, the utility is exploring ways to use natural gas demand response as a "non-pipe solution" to alleviate potential grid stress brought on by growing natural gas demand and pipeline constraints into New York City.

Con Ed's natural gas DR program is currently in pilot phase. If successful, expect other New York utilities to join ConEd and National grid in adopting it into similar programs of their own where gas pipeline constraints exist.

Non-Wires Solutions.

Non-wires solutions (NWS) are investments in the electric utility system that can defer or replace altogether the need for specific transmission and/or distribution projects.

NWS help to provide a cost-effective reduction of transmission congestion or distribution system constraints at times of peak demand.

New York is looking to implement several non-wires solutions, including fast-acting demand response with dispatch notices as short as five minutes and curtailment durations that last as long as 12 hours.

Organizations wishing to participate in such programs will likely need to accommodate the short dispatch notice with technology that facilitates automated DR.

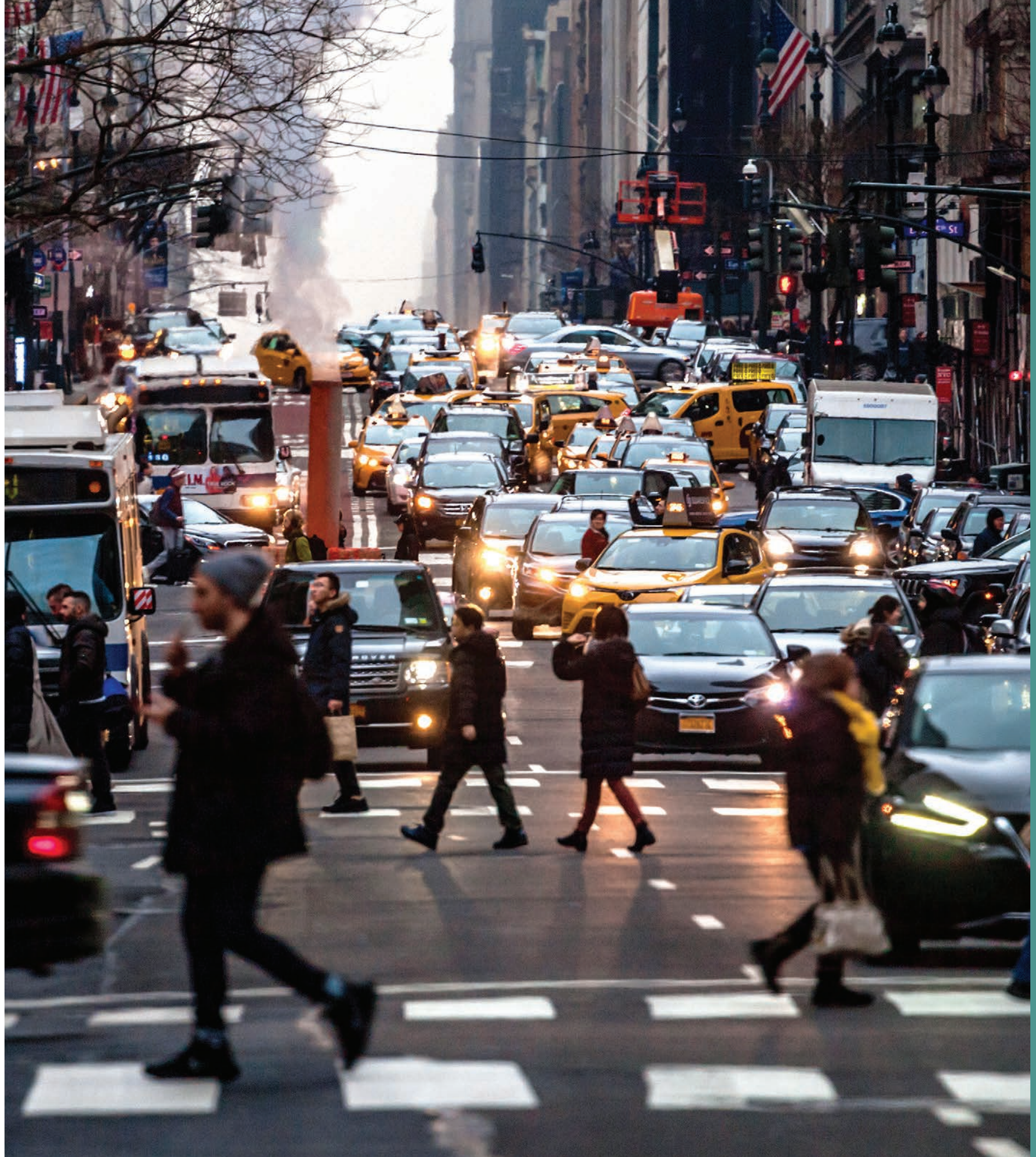
Energy Efficiency Initiatives in New York

On January 16 of this year, Governor Cuomo announced the state's Public Service Commission had approved an additional $2 billion (that's billion, with a "b") in energy efficiency and building electrification initiatives to further combat climate change.

The hefty investment stacks atop the $4.8 billion previously committed by the New York State Energy Research and Development Authority, the New York Power Authority, the Long Island Power Authority, and the Public Service Commission.

New York State is now committing $6.8 billion in support of New York's Green New Deal, which the governor has called a "nation-leading mandate to reduce greenhouse gas emissions throughout the state by 85% by 2050 and achieve economy-wide carbon neutrality."

The governor's office touts that these initiatives will help New York consumers save more than $13 billion on their utility bills over the life of the program, which aims to remove 3 million metric tons of carbon pollution--roughly the equivalent of 600,000 gas-powered cars.



NEW YORK

Rule 222: NYS DEC cracks down on NOx emissions from commercial generators

The New York State Department of Environmental Conservation (NYSDEC) has approved a new regulation called 6 NYCRR Part 222 Distribution Generation Sources. The rule replaces the March 1, 2017 adopted Part 222, which was challenged in the Supreme Court in the County of Albany and stayed.

Controlling nitrogen oxide emissions from distributed generation sources is Rule 222's essential goal. The rule will apply only in the New York City metropolitan area as defined at 6 NYCRR Part 200.1(au), which covers New York City, Westchester, Rockland, and Nassau counties.

DG sources enrolled in demand response programs sponsored by the NYISO or electric utilities as well as sources used during times when the cost of electricity supplied by utilities is high (defined separately in Part 222 as price-responsive "economic"generation sources) are subject to the new rule.[26]

Rule 222 was approved on March 11, 2020, and will be implemented effective May 1, 2021. Both new and existing distributed generation sources that intend to participate in DR will need to notify the NYSDEC by March 15, 2021 or 30 days prior to beginning participation, whichever is later. That said, organizations in the New York City metro area that use a stationary generator for demand response should contact CPower, since the rule could ultimately affect their ability to earn revenue by helping the grid reduce load in times of stress or high economic prices.

NYISO's DER Participation Model

On January 23, 2020, FERC approved NYISO's proposal to create a new participation model for aggregations of DERs to participate in the wholesale market. Many details remain to be sorted out, but come November 2021, new opportunities will be created to allow DERs and load curtailment to be aggregated and participate in capacity, energy, and ancillary service markets.

FERC also recently issued several orders that will impact whether renewable, storage, and SCR resources will be subjected to buyer-side mitigation (BSM) to prevent resources from exerting market power or have the ability to suppress capacity prices.

FERC has denied a joint NYS PSC and NYSERDA complaint against NYISO requesting energy storage resources be exempt from BSM. The Commission has also struck down NYISO's proposal to allow up to 1,000MW of renewable resources to be exempt from BSM for each Class Year.

FERC also changed its previous determination that exempted SCRs from BSM, now requiring all new SCRs in mitigated capacity zones to be subject to BSM tests. These decisions fly in the face of NY State public policies and will likely hinder developing resources that will help meet the goals of the CLCPA.

Final Thoughts:

2020 will be a big year for energy policy in the Empire State. Governor Cuomo's Reforming Energy Vision is entering its sixth year and continues to be the driving force behind the state's drive toward a cleaner energy future.

The question of whether regulation helps or hinders the evolving grid and the state's energy market is one that can spawn endless, passionate debate in New York. Still, it's an interesting lens through which the rest of the nation's deregulated energy markets are watching. New York likes it that way, believing that ambitious policies and supporting mandates are the keys to achieving a better, more sustainable future.

Commercial and Industrial organizations have a host of demand-side energy management opportunities to examine in 2020, many offering significant incentives. If we've learned anything about New York energy in the last five years, maybe it's the truth that the one thing New York residents like more than having the eyes of the nation on them, it's earning sound revenue in the process.

THE AUTHORS

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Pat has responsibility for CPower's demand-side energy management offerings in New York. He has extensive energy experience in the New York City energy market. Pat joined CPower from INF Associates, where he led the business development team to drive customer focused solutions to capture reduced costs savings and deliver maximum return on investment.

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CPower Sr. Director, Market Development

Peter has more than a decade of experience in the energy industry, primarily focused on demand response. He has advocated for DR interests in ISO/RTO stakeholder groups and with state regulatory bodies, as well as managed wholesale and retail DR portfolios across the ERCOT, CAISO, and NYISO markets.

PJM

January 7, 2014 is a day that may very well live in infamy for PJM, the largest grid operator in the US.

That evening, amidst plummeting temperatures that were 25 degrees below the seasonal average, PJM set what was at the time a new winter peak demand record of 142,980 megawatts as residents came home from work and cranked their heat.

At the peak demand hour, PJM's grid experienced a calamity. Piles of coal had frozen over. Natural gas pipelines were interrupted. Gas igniters failed. Trucks were unable to deliver much-needed fuel to backup oil plants. 22% of the grid's total capacity went offline, forcing 40,200 megawatts of outages in the region.

PJM was able to weather the storm and ultimately meet the unprecedented demand but not before suffering exceptionally high wholesale power costs driven by heavy electricity use for heating and high natural gas prices.[27]

In the wake of what would come to be called the Polar Vortex of 2014, PJM altered the way it went about procuring demand response resources in the winter. Demand response (DR) had played a heroic role in helping PJM restore balance to its grid that exceptionally frigid January in 2014. Still, the RTO knew it needed to make a change to avoid outages brought about by extreme weather.

2020 marks the first year in which PJM has shifted entirely away from predominantly summer demand response to Capacity Performance, which requires year-round DR availability from its participants.

The move stirred a great deal of anxiety among DR participants accustomed to summer-only responsibility. But, as we'll see in the next few pages, PJM's market is evolving in a way that aims to keep the lights on during the cold and allow organizations to participate in DR on terms that suit their capabilities.

The key to it all is zonal aggregation and, as it turns out, when it comes to aggregation in PJM...size really does matter.

What is Zonal Aggregation?

In 2019, PJM adopted new rules that allowed customers to contribute different seasonal load values if their curtailment service provider (CSP) can find an offsetting match for the lesser of the two seasonal values within that particular zone.

This practice is called zonal aggregation.

In short, zonal aggregation is what enables a given customer to contribute different seasonal load values in PJM's Capacity Performance demand response program, which otherwise requires a single year-round load drop value from its participants.

Before we get into the details of how zonal aggregation works, lets review the rules (and customer concerns) of PJM's year round demand response program.

Capacity Performance

Heading into 2020, a common concern many organizations that had previously participated in PJM's summer-only demand response went something like this: will we have enough winter load to satisfy the new year-round participation requirements?

It's a valid concern given Capacity Performance's parameters which essentially state that a participant has both a winter load drop value and a summer load drop value. Those values can be different, but the lesser of the two values is what PJM counts as a given organization's year-round load value.

Let's put some numbers to the example above. If an organization has, say, 5 MW of curtailable load in the summer but only 2 MW in the winter, then the organization's year round load would be 2 MW-- the lesser of the two values.

To its credit, PJM realized it had roughly 50% more potential capacity in the summer than winter and that quality seasonal capacity was essentially being kept on the sidelines. The RTO realized it had to make a change.

Enter zonal aggregation.

How Zonal Aggregation Affects CP

Let's turn back to our example of a customer with 5 MW of curtailable load in the summer but only 2 MW available in the winter.

Instead of having to enroll for the year at the lesser load value (2 MW), the customer can contribute 5 MW of load reduction in the summer and 2 MW in the winter if (and only if) the curtailment service provider (CSP) they're working with can find another customer in the same zone with 3 MW of excess winter load reduction to offset the original customer's shortage.

This creates what is called a CP aggregation within the CSP's demand response portfolio.

Bigger really is better

(when it comes to zonal aggregation portfolios)

Organizations seeking to participate in Capacity Performance and contribute different seasonal load drop values through zonal aggregation need to work with a licensed CSP with--and this is important-- a sizable CP aggregation in its demand response portfolio.

Why, in this case does the size of the aggregation portfolio matter?

Consider a small CSP that has just a few organizations' loads in its portfolio. What are the chances this small CSP is able to find a seasonal load match for a particular organization in a particular zone? Not likely.

On the other hand, a CSP with a large aggregation portfolio that includes loads of many organizations located in many zones is much more likely to be able to find the same offsetting match.[28]

The Reliability Pricing Model (RPM)

Let's take the next few paragraphs and provide just enough information to make you sound like a cocktail party expert on how PJM procures capacity.[29]

PJM is a forward capacity market in which capacity resources participate by selling their available capacity into the Reliability Pricing Model (RPM) to meet PJM's forecasted load needed to ensure reliability in each delivery year.

The RPM is made up of four auctions. The Base Residual Auction (BRA) is the first and largest auction PJM conducts and is held three years in advance of the delivery year.

PJM also conducts three Incremental Auctions (IA). IAs take place once a year and allow PJM to adjust their load forecast. They also allow other market participants to buy and sell capacity as needed.

Once an RPM commitment has cleared any one of the four auctions, the market participant is then obligated to deliver that capacity on June 1 of the designated delivery year.

Resource Adequacy in PJM: too much a good thing?

PJM has been criticized of late (along with several other grid operators in the US) of over-procuring resources in its capacity market. At 29% in 2019, PJM had the second-highest anticipated reserve margin among deregulated energy markets in the US.[30]

Over the past ten years, PJMs system peaks have been flat or declining, highlighting the region's over-forecasting woes.

In PJM's defense, there are two significant reasons why the RTO has consistently taken a long position on resource procurement. Both have the rate-paying customer in mind.

For one, if PJM has the option to buy cheap capacity due to there being an abundance of it, they buy it. Consider the alternative, if less capacity were available it would cost more and eventually rate payers would end up seeing higher prices on their electricity bills.

Next, PJM has historically over forecast its requirements, resulting in the RTO purchasing a good deal more capacity than it needs in the Base Residual Auction (BRA) and selling it back in the Incremental Auctions (IAs), which are held so PJM can make exactly those kinds of adjust-ments.

Over procurement of resources isn't necessarily a bad thing, but PJM is nonetheless seeking to improve its load forecasting methods.

Exactly what that will entail is yet unknown, but any adjustment will likely affect capacity prices in future forward capacity auctions, potentially driving them down since PJM will be seeking less capacity once its forecasting is honed.

That's in the future. Let's spend the next few minutes looking at what's affecting PJM's present and subsequent push to tomorrow.

PJM's drive to the future

Every deregulated energy market in the US is working to evolve its grid's fuel mix from fossil based sources to those that are cleaner and more renewable. To borrow an archetype from a fable we all know, some markets--California, New York, and New England, for example--have chosen to sprint ahead like rabbits and lead the march toward energy's future.

PJM prefers to play the role of the hare, opting for a much slower evolution of its grid. Their logic is sound. Let the other markets take an early-adopter position and learn from their wins and mistakes. All the while, work to keep the grid at home reliable and the rates reasonable for consumers.

That steady-as-we-go attitude helps explain that while PJM is working to integrate distributed energy resources onto its grid, there currently aren't ample opportunities to monetize these resources in the marketplace.

Monetizing DERs in PJM

Currently there are no opportunities to monetize front-of-the-meter distributed generation in PJM. Few opportunities exist behind the meter, either. That will likely change in the near future. Before we get into the reasons why, let's define DERs and explain how they interact with the grid.

Distributed Energy Resources (DERs) are, technically-speaking, resources that are connected to the grid at the distribution level rather than at the transmission level. The distinction is important to energy wonks because the rules in PJM for connecting to distribution lines differ from the rules for connecting at the transmission level.

Resources that are in front of the meter (meaning they do not serve a retail load directly) are treated the same in the market place as any other resource, once they're connected to the grid. Many DERs, however, are behind the retail meter and help offset customer loads purchased from the grid.[31]

As long as the DER does not inject into the grid (i.e. generate more kW than there is load) the DER can be treated as demand response.[32] However, if the DER is able to inject and offset the owner's load, things get really complicated, especially if the owner can curtail load (shut down processes, reduce lighting, etc) in addition to operating energy sources.

Commercial and industrial organizations especially desire DERs and have been implementing them behind their meters for the last several years. They're doing this for their own reasons, namely to reduce demand, transmission, and energy costs while upping their organization's resilience. If the economics are right, there is no reason to think behind-the-meter DER implementation won't grow in the future.

If PJM doesn't soon devise ways to allow these popular resources to be monetized, the grid operator may find itself in the unenviable position of not having enough demand-side resources to call on during times of grid stress or unusually high prices. That's because the more organizations incorporate behind-the-meter distributed resources to generate their own electricity the less load they're drawing from the grid. The consumers' meters are essentially dropping, meaning they are consuming less electricity from the grid. This inevitably leads to less load that the grid can call on via demand response when the grid is stressed or electricity prices are high. PJM's forecasting takes this loss of load into account and therefore needs less load to procure.

PJM is working on these issues, but progress has been slow.

Demand Response in PJM

In addition to the Capacity Performance program we've discussed, PJM also offers the following demand response programs in 2020.

Economic Demand Response:

PJM's Economic Load Response programs allow participating businesses to manage their electricity use in response to conditions in the wholesale energy market. Participants are notified when wholesale electricity prices are high and reduce their electric consumption, thereby minimizing the impact of price spikes, reducing the need for expensive capacity generation, and helping keep prices stable in the market.

Ancillary Services:

PJM Synchronized Reserves Program helps the grid react to short-term disturbances. Each hour, customers may offer a price at which they're willing to be available to curtail if needed.

If their offer is accepted, they receive at least their offer price and must be on-call to curtail for up to 30 minutes to within 8 minutes of an event notification.

PJM's Frequency Regulation Program is available 24/7/365.

Resources in the Frequency Regulation market must be able to respond within seconds to fluctuations between generation and consumption on the PJM grid.

Participating organizations earn money for being available to rapidly increase and decrease their usage in response to a dynamic signal and are measured on their ability to perform when signaled.

Utility Demand Response Programs:

PA Act 129 Program allows participants to further augment the payments earned via participation in emergency capacity and/or economic programs.

Pennsylvania's Act 129, signed into law in 2008, set ambitious savings and demand reduction goals for the state's large electric utilities such as PPL, PECO, FirstEnergy, and others. Registrations are currently open for Phase III of Act 129, a four-year program that runs from 6/1/2016 to 5/31/2021..

The Minimum Offer Price Rule (MOPR)

In 2006, when the RPM was introduced, PJM also issued a Minimum Price Offer Rule to establish a price floor and impose a minimum offer screening process to ensure new generators could not artificially depress capacity auction clearing prices through low-cost bids.

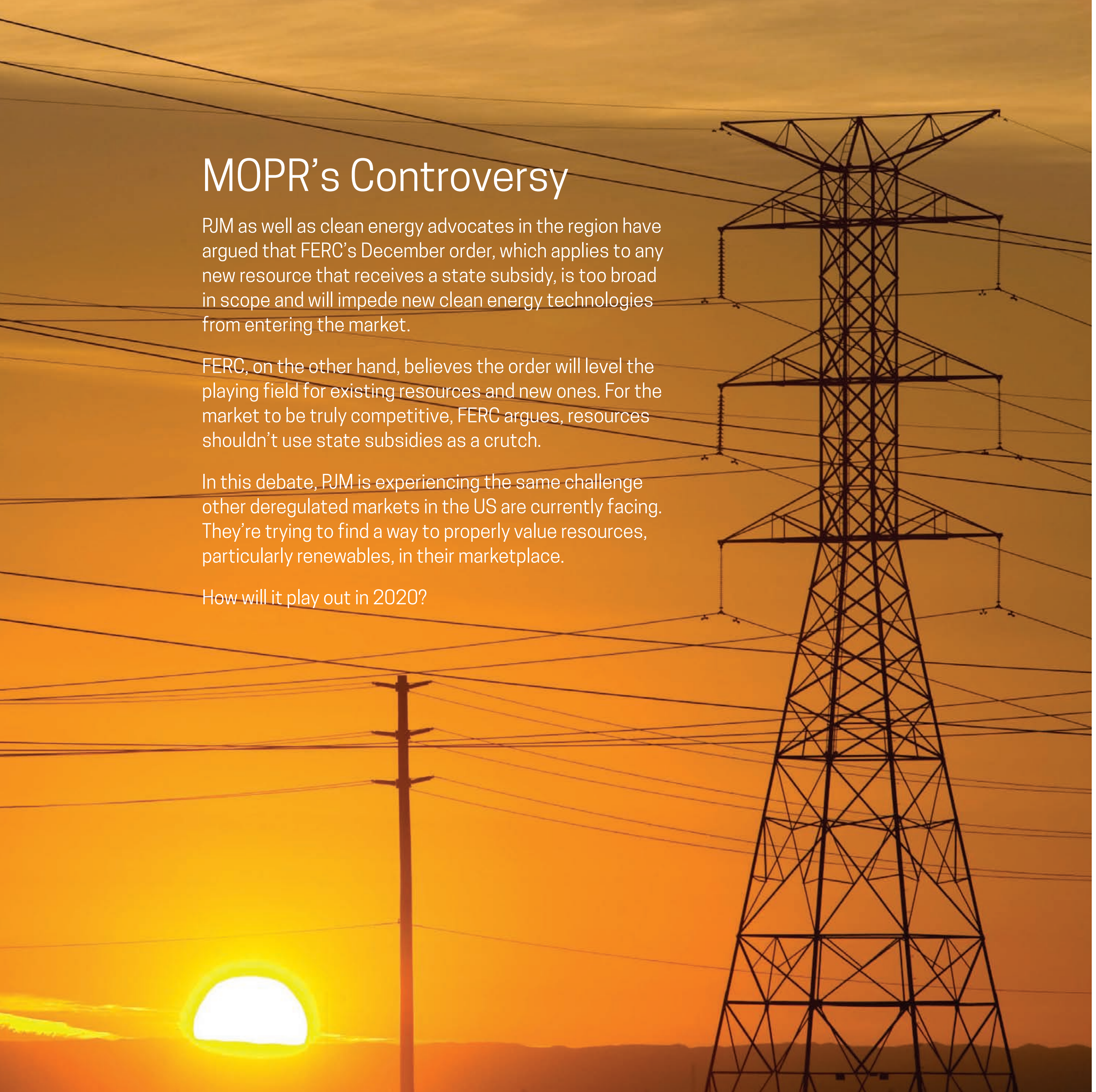
The original rule did not target existing baseload resources whose plants took longer than three years to build such as nuclear, coal, integrated gasification combined cycle (IGCC) and hydro plants. Rather, the rule focused largely on new, non-exempted natural gas-fired resources.

Faced with a host of natural gas resources entering the market, PJM was hedging against capacity prices being depressed in its auction and rendering existing resources to a non-competitive fate. State-subsidized resources like nuclear and renewables, PJM reasoned, could suppress overall market prices by presenting falsely low prices in auctions.

And so, the rule as it was implemented in 2006 required new resources (including natural gas) to offer at or above the price floor, equal to the net cost of new entry (Net CONE) for the applicable asset class.

On December 19, 2019, the Federal Energy Regulatory Commission (FERC) issued an order to PJM, calling on the RTO to expand its Minimum Price Offer Rule, requiring nearly all state-subsidized power resources inside and outside PJM's footprint to offer capacity at a PJM-determined price floor in order to participate in the RPM.

The December order has sparked heated debate between PJM and FERC.



MOPR's Controversy

PJM as well as clean energy advocates in the region have argued that FERC's December order, which applies to any new resource that receives a state subsidy, is too broad in scope and will impede new clean energy technologies from entering the market.

FERC, on the other hand, believes the order will level the playing field for existing resources and new ones. For the market to be truly competitive, FERC argues, resources shouldn't use state subsidies as a crutch.

In this debate, PJM is experiencing the same challenge other deregulated markets in the US are currently facing. They're trying to find a way to properly value resources, particularly renewables, in their marketplace.

How will it play out in 2020?

MOPR's Impact in 2020

Climate change is a driver in PJM as it is in other markets. In PJM, a region that is home to many of the nation's largest coal plants, there are proponents on both sides of the energy portion of the issue's debate.

In the absence of federal action, states are drafting their own legislation to handle the challenge of providing cost-efficient, reliable energy to their citizens in an environmentally-sensitive way. Many states in PJM support the notion that non-carbon resources such as nuclear plants need to be supported so they may be kept online as a bridge resource to maintain reliability and low costs until renewables like energy storage are viable.

The issue with MOPR involves state-level subsidies. What energy resources, if any at all, should get subsidized? More to the point for organizations eyeing how their demand-side management might be impacted, if only energy resources are subsidized, how will that affect capacity prices in the market?

The concern is that capacity prices will be driven down. That would greatly affect organizations that have been successfully using demand response to offset their rising energy costs.

The issue at the core of MOPR is divisive. Some argue the ruling is necessary to keep PJM's grid reliable and its market efficient as the region transitions its fuel mix from fossil to renewable sources. Others contend the ruling thwarts PJM's evolution toward a cleaner energy future.

The impact of the ruling, and any regulatory policies that may be issued as a result of it, is bound to have an impact on PJM's capacity market. That's what we'll be watching in 2020.

Energy Efficiency in PJM

In PJM, businesses can earn revenue for permanent load reduction resulting from energy efficiency projects they have completed or will be completed in the future. PJM's energy efficiency program pays organizations capacity revenue for up to four years following the completion of a qualified project.

Qualifying projects include:

- Lighting
- Refrigeration
- HVAC
- Motors
- Variable-Frequency Drives (VFDs)
- Compressed Air
- Industrial Process Improvements
- Weatherization/Building Envelope
- LEED/Green Building
- New construction projects exceeding industry standards

Earning with EE in PJM

The moment an organization completes an energy efficiency (EE) project, it begins to realize savings on its electricity bill.

Assuming the organization has retained the capacity rights from the EE project, a licensed curtailment service provider (CSP) can then offer the organization's reduced capacity into PJM's capacity market, turning the "NegaWatts" (curtailed load) into another revenue stream.

The EE project will continue to earn revenue from PJM for 4 years after completion. Savings continue forever.

Final Thoughts:

PJM has proven to be a traditionally slow-moving market when it comes to transitioning to a renewable future. That doesn't mean, however, the largest wholesale energy market in the US isn't amidst a transition.

Unlike more progressive markets in the US, like California and New York who prefer to run at the front of the renewable pack, PJM remains cautious and logical, with their grid's reliability and their ratepayer's electricity bill top-of-mind. No sense, PJM reasons, in rushing out to solve one problem only to realize you've unwittingly caused three new ones.

Change, though, is inevitable when it comes to energy markets. If it isn't customer demand for cost-effective electricity from clean sources, it's Mother Nature herself who unleashes the winds of change and demands the grid evolve with the times.

2020 looks to be a year during which PJM will learn a lot about the path it's taken. The first year of year-round-only demand response coupled with the inevitable final ruling and eventual policies stemming from the MOPR will likely play out between now and the end of the year.

2020 is going to be a big year for the nation's biggest market. If you need any help figuring any part of it out. Give us a call. We'll be ready. Always.

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Mr. Price has specialized in PJM Demand Response for the last ten years. As CPower's Executive Director of Market Development for the PJM market, he is responsible for keeping hundreds of customers up to speed on market conditions, energy prices, program particulars, and regulatory issues in the ever-changing PJM Demand Response market.

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Ed has responsibility for demand-side energy management offerings in PJM. His career has focused on the underlying technologies and businesses that promote sustainability, resilience, and efficiency. This includes spearheading early deployments of distribution automation and demand response on electric grids and full-out smart grid meter and system deployments at rural electric cooperatives.

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CALIFORNIA

1 drought.gov--US Drought Portal; National Integrated Drought Information System

2 water.ca.gov--California Department of Water Resources

3 Q3 Report on Market Issues and Performance; CAISO--December 5, 2019

4 RPS-eligible resources include solar PV, solar thermal, hydroelectricity, geothermal, and bioenergy. (cpuc.ca.gov/rps)

5 cpuc.gov

6 For regular updates on California's energy market evolution, see CAISO.com or contact CPower

7. Widely considered among California residents to be the energy industry's most annoying acronym

TEXAS

8. As of this writing. Wind accounts for about 20% of ERCOT's fuel mix.

9. Solar Energy Industries Association (SEIA)

10. Apologies if this statement caused readers from California and New York to throw up a little in their mouths.

11. ERCOT Contingency Reserve Service Working document--protocol definition for Contingency Reserve (CR) service.

12. The exact opposite happened with demand response in California in 2019. Participants in the Golden State were called often and paid poorly, resulting in "demand response fatigue."

MISO

13 Miso Forward: Delivering Reliability and Value in a 3D Future; MISO, March 2019.

14 Ibid.

15 MISO Forward

16 Ibid

17 Federal Energy Reserve Commission Docket No. ER19-650-000 Order Accepting Tariff Revisions, Subject to Condition, and Granting Waiver. (Issued February 18, 2019)

17b As long as Tom Brady is a Patriot.

NEW ENGLAND

18 Energy Security Improvements; ISO New England--ISO discussion paper, version 1

19 ISO-NE Forward Capacity Market (FCA 13) Result Report

NEW YORK

20 Six years can be a span that yields singular, lasting achievements. For example, it took Leo Tolstoy six years (1863-1870) to write War and Peace. A lot can happen in six years, however. Actor and socialite Zsa Zsa Gabor was divorced three times from three different men during a six year span from 1977-1983.

21 Reliability and Market Considerations for a Grid in Transition; NYISO, May 2019.

22 New York State Energy Research and Development Authority (NYSERDA.gov)

23 rules.cityofnewyork.us

24 NFPA press release; September 11, 2019

25 Federal Energy Regulatory Commission--Docket Nos ER19-2276-000 (001 and 002); Order accepting tariff revisions and directing compliance filing and information report

26 New York State Register, VOL XL II Issue 10, page 5

PJM

27 Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events; PJM Interconnection--May 8 2014

28 CPower is such a CSP with a large aggregation profile in PJM. (we could hear you wondering aloud.)

29 There isn't enough beer in Milwaukee to make PJM's RPM party-worthy conversation. Trust us on this.

30 US Energy Information Administration, based on NERC 2019 Summer Reliability Assessment

31 Battery storage and backup generators are examples of DERs that can be monetized in demand response programs in PJM.

32 Behind the meter solar can't be monetized even as demand response.

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