Future Electricity Markets

Designing for Massive Amounts of Zero-Variable-Cost Renewable Resources

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THE INCREASE IN VARIABLE renewable energy (VRE) on the bulk power system can create both challenges and opportunities, as described throughout this issue of *IEEE Power & Energy Magazine*. Many regions across the world are starting to approach penetration percentages that were unprecedented during the initial introduction of organized wholesale electricity markets. We have seen that market operators, market participants, and regulators have been up to the task. They have prioritized, designed, and implemented market-design changes to accommodate the variability, uncertainty, near-zero-cost, and emissions-free attributes of these resources. The challenge is to ensure that electricity is provided reliably and economically, with compatible incentives to compensate the parties that contribute to doing so. Around the world, markets are experiencing increasing levels of renewables, and ongoing design enhancements are being discussed. Market operators can borrow design characteristics from each other and learn which designs may or may not work. However, as an industry, we are starting to look

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past these modestly high penetration percentages of VRE. We are starting to ask what a market would look like if the entire energy supply for a particular interval were supplied with 70, 80, 90, or 100% renewable resources.

European countries, such as Denmark, Ireland, Germany, and Spain, have already seen hours of 138, 88, 89, and 64% energy supplied by wind and solar power, respectively (with Ireland being a single interconnection). In the United States, the Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), and California Independent System Operator (CAISO) have seen hours of 56, 66, and 65% energy supplied by wind and solar power, respectively. CAISO has served 93% of the load from carbon-free resources, and Kansas has served 106% of the load from wind in a single hour. In South Australia, served by the Australian Electricity Market Operator (AEMO), the amount of energy from renewables is anticipated to surpass the load by 2020. Asking what, if any, transformational changes to the electricity markets are needed to meet 100% instantaneous renewable levels is not just an academic thought exercise; it is something for which these market operators need to prepare. If significant market-design changes are necessary for an economic and reliable system under these scenarios, they may require several transitional steps to get there.

As discussed throughout this issue of the magazine (see the articles by Lew et al. and Matevosyan et al.), variable renewables, such as wind and solar, have unique characteristics, and many of these characteristics affect the outcomes of electricity markets and their potential design evolution. These resources have variability and uncertainty, creating a greater need for operational flexibility. Compensation must be available so that existing resources have an incentive to provide flexibility and new or modified ones have an incentive to build or retrofit with the needed flexibility. As most variable renewables are nonsynchronous resources, additional incentives may be needed to ensure that the necessary attributes of synchronous resources are maintained or developed through other innovative ways. Finally, as wind and solar do not incur a cost to supply their natural fuel, their expenditures are entirely made up of capital, operations, and maintenance expenses. The majority of market designs across the world focus on marginal cost pricing and incentivizing for more efficient heat rates and lower fuel expenses. The greater amount of renewables entering the system can challenge whether incentivizing for these characteristics is still valid.

There are many possible paths electricity markets could take, and there is no simple answer to the question of which one is best. We have no crystal ball and acknowledge that a region's market design is driven by stakeholders and regulators. We also do not answer the question of what a successful market design looks like. This article asks questions about what may be expected and how markets may be able to address the challenges of high VRE levels. More research, analysis, and good old trial and error will help the industry understand the potential designs that may lead to desired outcomes for these scenarios.

Markets Accommodating the Unique Characteristics of VRE

To start the discussion on how the designs of electricity markets may look in the future, it is important to review some significant changes that have been introduced. In an article written two years ago, many changes to electricity markets were discussed (Ela et al., 2017), including market expansion and coordination, phase-out of priority dispatch support, new and evolving ancillary service products, designs for greater ramping capabilities, intraday markets, and price formation changes. In this section, we will expand on recent design changes in a few regions experiencing high VRE levels.

CAISO has made numerous changes to incentivize flexibility and ensure it is being provided. The company recently proposed enhancing its day-ahead market by moving from the current hourly granularity to a 15-min granularity. This can better position resources to accommodate the net load ramps that occur in real time by using more information about when those ramps may happen within the hour. Currently, the real-time market must dispatch resources to manage granularity differences between the hourly day-ahead and the 5-min real-time markets. As Figure 1 illustrates, this can allow the commitment of resources in advance to ensure that when faster ramps occur in real time, they are met with day-ahead resource commitments and prices in the day-ahead market are aligned with real time when those greater ramps are expected.

SPP has developed market tools, such as separate regulation-up and -down products to incentivize all generation types to provide specific value to the system. This presents an opportunity for VRE to participate in regulation down without having to curtail in advance. SPP is currently assessing a ramping product that will provide incentives for the ramping events experienced by it and is also evaluating the development of an uncertainty product that assists with net load changes in longer periods than traditional ancillary services products (e.g., longer than 1 h). New products to ensure available ramping for different horizons are available in several U.S. markets.

ERCOT serves an "energy-only" market with no capacity market. Its planning reserve margin trends have declined from a 2017 summer forecast of 9.4% to a 2019 summer forecast of 7.4% and a nonbinding target of 13.75% (Figure 2), the lowest of any region in the continental United States. Although this decline is not entirely due to renewable resources, the energy price reduction, which can be due to both lower natural gas prices and zero-variable-cost renewables shifting the supply stack, is certainly related. ERCOT had introduced the operating reserve demand curve (ORDC) to supplement energy revenue when the system is stressed. The ORDC is a downward-sloping curve that sets a price based on the amount of operating reserve available and how that impacts the probability of being short on energy. It is then paid to all energy providers in addition to the energy price. Recently, the Texas Public Utility Commission approved changes to the ORDC with the intent to incentivize investment and, thus, increase the reserve margins to achieve goals of a long-term market equilibrium in line with target reliability reserve margins.

Europe has developed a set of rules and guidelines to harmonize day-ahead, intraday, and balancing markets across regions to enable cross-border trade on interconnectors in all of these time frames. In 2018, a pan-European single intraday platform, XBID, was put into operation, and work is ongoing to have similar European platforms for balancing products. Intraday markets have been particularly important, with the industry reluctant to make significant changes (e.g., feed-in tariffs and priority dispatch) before a liquid intraday market was introduced. Wind and solar are increasingly participating in the markets, with mandatory participation, penalties avoidance, or ancillary services revenues as reasons. Curtailing wind production when necessary has become an important option in the new design.

In 2007, the Irish markets were joined together as the Single Electricity Market, a single-pool market with day-ahead and intraday markets. It has an explicit market-wide capacity mechanism to incentivize availability at peak times. Significant work has also been done to reinvent an appropriate system-services procurement framework for provision of services from any technology. This framework has facilitated a fundamental transformation of the capability of existing plants, including reducing more than 400 MW in minimum generation limits, incentives for demand management, and an allowance for wind to provide operating reserves. The revised framework has incentivized sufficient capability to manage instantaneous penetrations of up to 75% of nonsynchronous technologies. Augmenting this system-services framework further to facilitate the

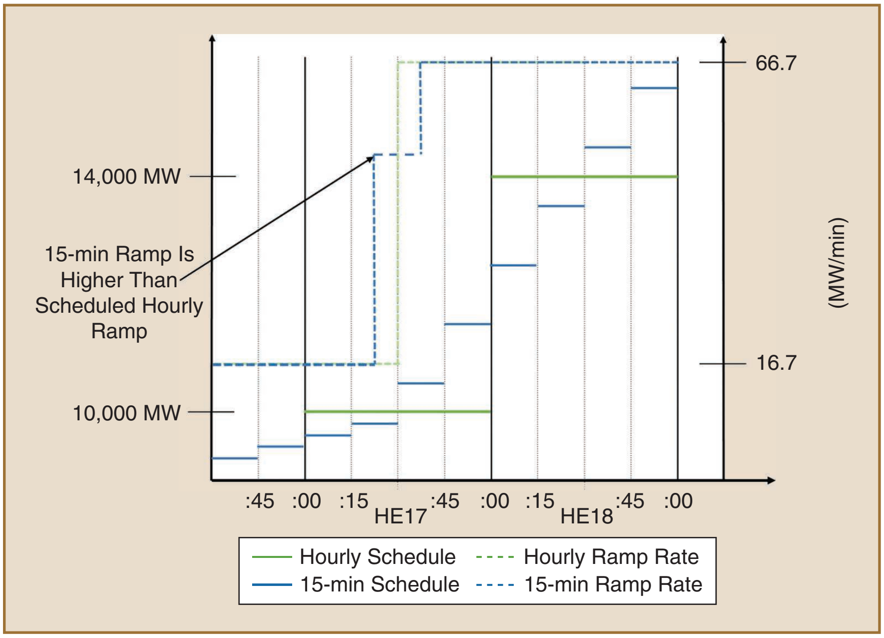

figure 1. A comparison of the CAISO 15-min versus hourly day-ahead ramp. HE: hour-ending intervals.

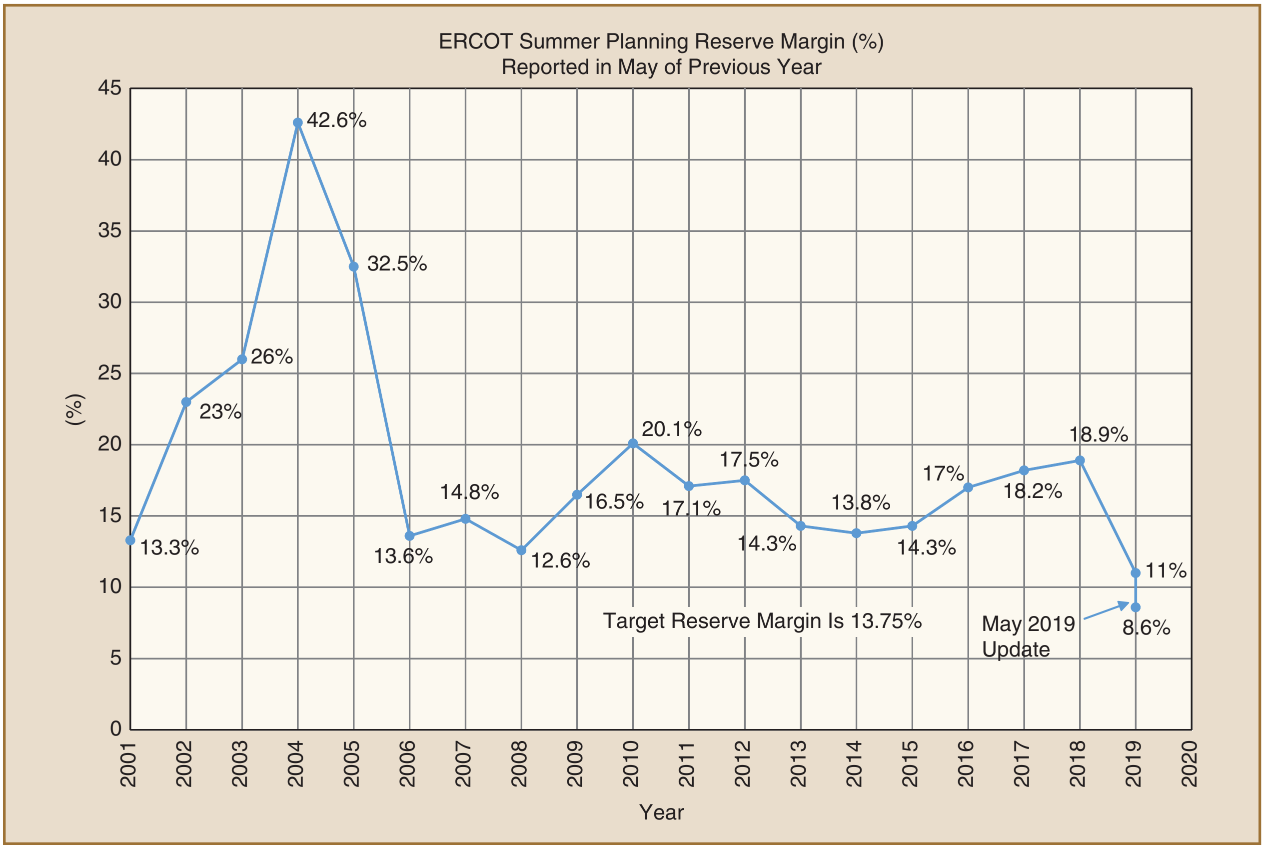

figure 2. The ERCOT reserve margins have fallen dramatically.

more than 95% instantaneous penetration of VRE is essential in meeting the Irish government's target of 70% annual renewable supply by 2030.

Australia has observed increasing interventions in the market for the purposes of maintaining system security. In 2018, AEMO intervened to commit synchronous units in South Australia for a minimum of 40% of all intervals to maintain system strength (as high as 65% in some months). Most of AEMO's interventions have occurred during periods of lower prices (Figure 3) or when the gas fleet is on outage. In these periods, there is an absence of incentives to keep units committed. Nonsynchronous generation (primarily wind) has also been curtailed to maintain system strength. This emphasizes the importance of having a market design that fully incorporates the full suite of technical requirements critical for operating a complex electrical system.

Future Markets: Large Overhaul or Incremental Adjustments?

The primary question being asked is how significant the design changes need to be to enable a market with a nearly full supply of renewable energy. Although many electricity

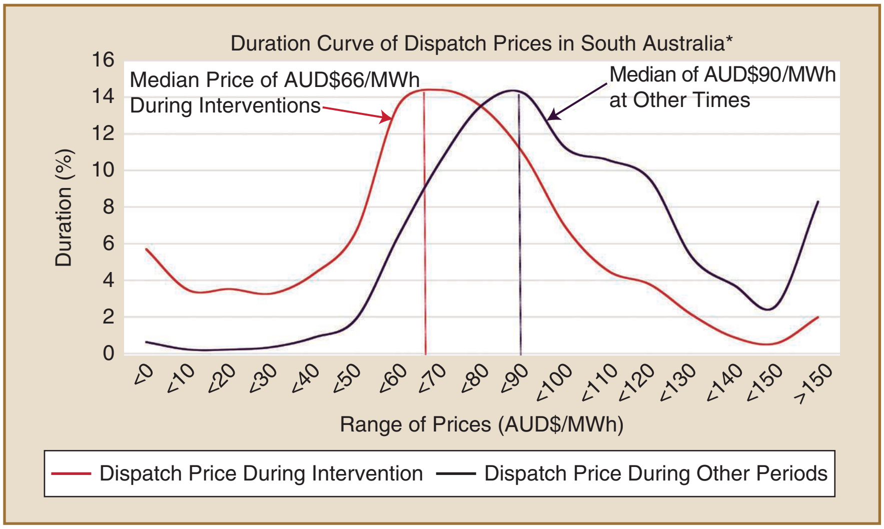

figure 3. The duration curve of prices during system directions in Australia. The asterisk denotes unadjusted dispatch reference price for South Australia during 2018.

markets are designed to align with the physics of electricity generation and delivery, existing designs differ across the globe. Will these designs continue to provide the right incentives for industry to deliver reliable and affordable power? Will continued tweaks be necessary to accommodate the changing characteristics? Or will the industry see large restructuring efforts, such that existing designs are no longer feasible given the substantial changes needed to supply this much energy from resources with the characteristics described? We do not have the answers but provide insights on where some of the discussion has been to date.

Although market designs differ across the globe, most regions have a central focus on prices based on marginal operating costs to supply energy. By reducing energy supply costs, typically through heat-rate improvements and fuel-cost reductions on thermal plants, the participant earns a higher profit when the cost of the marginal providers is unchanged. For a system with primarily renewable resources supplying energy, the incentive to reduce operating costs is not necessary; the operating costs are generally as low as they can be. So to answer the market-design question, we start by asking what other attributes and behaviors a market should incentivize on this future system. This may include the following characteristics:

- ✔ lower costs for capital, operations, and maintenance
- ✔ locating supply so energy can be delivered where it is needed and reducing the infrastructure (e.g., transmission) costs
- ✔ providing the most energy per installed unit of capacity (increasing capacity factors, which is similar to lowering capital costs)
- ✔ reducing the impact of variability and uncertainty and potential for load shedding or other reliability consequences
- ✔ providing sufficient reliability services
- ✔ demand-side participation.

Many of these attributes are incentivized in existing market designs. With different outcomes and participant behavior, it is unclear whether the features that incentivize these attributes today will still be there tomorrow. We review three components of the electricity-market suite of products: the energy market, the reliability services markets, and other products or services that may or may not yet exist.

The Bread and Butter of Electricity Markets: The Energy Market

In nearly all electricity markets around the world, the energy market is the prime source of revenue for market participants. All other services are there to support the energy market. Prices are typically based on the marginal operating cost of supplying energy, approximated as the variable cost of the most expensive resource selected to supply energy. Energy markets have gone through various reforms since their inception, with some significant changes. U.S. markets use locational marginal pricing for every generator node on the system, with centralized unit commitment and economic dispatch as well as prices that often include three-part offer costs (startup cost, minimum-load costs, and energy-offer curve). European markets typically have zonal prices with decentralized unit commitment and single-part offers (startup and no load must be included in the single offer). In markets like ERCOT and AEMO, the only revenues available are from the energy and reliability services markets, whereas others have capacity payments of some form. Although there have been some substantial changes, not many are due to increasing levels of variable renewables entering the market.

With increasing zero-variable-cost VRE, we may observe more periods of lower prices during high VRE production, which can make it difficult for the remaining generators to recover their costs. These generators may either increase their offer prices to recover those costs (which may trigger automatic mitigation of offers or make them uncompetitive), have other administrative “adders” to the price, earn greater revenue in other products where they exist (e.g., capacity markets), or face “missing money” and potentially withdraw from the market. If the resources that withdraw due to insufficient revenue are still needed by the grid operator, it is possible that the market design is flawed and needs modification. In existing designs, when this happens, out-of-market actions may take place.

Although lower energy prices are anticipated on systems with higher renewables, this is not necessarily proven in all cases. Today, when a system is at greater risk, prices are set by administrative “shortage” prices, values that often exceed US$1,000/MWh in the United States. Typically, the system is short in operating reserve, and this reserve shortage price is then reflected in the energy price. If these conditions occur more frequently than today or if market operators adjusted the set of conditions that trigger these prices, the overall average energy price may not necessarily be lower. With the existing market design, there could be a situation where the price is either zero or set at the high-shortage value. Since this discontinuity may not be politically desired, designs can be modified by triggering price increases as the system approaches, rather than exceeds, shortage conditions. Alternatively, consumers can set those shortage prices as opposed to having the market operator (with the agreement of stakeholders and regulatory agencies) set administrative values. As can be seen in Figure 4, there is no clear trend on increasing shortage pricing due to increased renewables. However, in some regions, such as CAISO, shortages are often triggered by a lack of ramp available during the evening (when load picks up and solar photovoltaic declines) rather than a capacity shortage. It will be essential to observe the frequency and causes of these shortage prices in the future and see whether demand plays a more defined role.

Traditional approaches to demand response (DR) have focused on incentivizing load reduction. However, recent studies have defined additional value that DR can provide to a grid, including load shifting (the movement of energy consumption from times of high demand to times of surplus generation) and load shimmy (dynamic adjustment of demand to alleviate short-run ramps and disturbances). Market design should adapt to exploit the full scope of value from the demand side. CAISO is considering the development of a load-shift product, whereby incentives are provided to behind-the-meter technologies to consume excess renewable energy and supply it back when it is needed.

There are questions about the market timelines as well. Some regions are looking at multiple-day-forward markets to better capture the optimal use of fuel from heavy natural gas use and energy storage. Other regions may see a decrease in resources that need substantial time to staff and synchronize to the grid, thus reducing the need for a day-ahead market. As VRE forecasting errors tend to reduce significantly as we approach real time, would this reduce the benefits of day-ahead markets, which increasingly deviate from real-time conditions? Europe has observed shifts away from day-ahead markets toward intraday and real-time markets. Do ahead markets need to be more responsive to the forecasting time frames for VRE?

Reliability Services of the Future

Since the introduction of electricity markets, reliability services markets have existed to provide individual price and quantity schedules for different services needed to maintain the reliability of the bulk power system. Other reliability services have rules for how and which costs can be recovered. The number of reliability services has grown, with new services being added by market operators due to new challenges being introduced by VRE. The design of these reliability services markets (also referred to as *ancillary services*) differs across the globe. U.S. markets align them closely with energy markets using co-optimization and marginal cost pricing for every market interval, whereas other areas use contracting and bilateral trading for many services. Markets may exist for contingency reserve, regulating reserve, frequency response, voltage support, and black-start services. What has been generally consistent across different markets is that, although these service markets crucially provide the incentives to ensure a reliable electric system, they are an afterthought based on the small amount of revenue actually earned in them. An important question for any changes to reliability services market design is whether or not that will continue to hold or if these markets will become an increasing revenue source for those resources that provide services as much as they provide energy.

With predominantly low energy prices, increases in reliability service requirements, and displacement of the resources that historically provided these services due to the lower energy prices, revenue from reliability service markets may become a greater proportion of overall revenue sources. However, if the service is abundant and can be provided cheaply, this may not be the case, no matter how crucial that service is. For example, a single bolt on an airplane is very crucial, and its absence could be catastrophic. However, the bolt is still valued at just a few cents. If the services become scarce or more expensive to produce, this can change the paradigm. Again, the key will be setting shortage price levels and triggering points to send the appropriate price signals or allowing consumers to better direct prices. At high VRE penetration levels, certain reliability services become more valuable: inertia, fast frequency response (FFR), frequency regulation, and reserves to cover against renewable forecast error. Some of these were in plentiful supply with yesterday's generation portfolio. Now, we need to make sure the market includes compensation for scarcity providers of reliability services going forward.

Reliability service markets have different definitions, requirements, and eligibility rules. Some definitions are somewhat archaic, others are based on existing characteristics other than explicit needs, and still others may aggregate multiple services as one to make things simpler. The first step may be to ensure that the definitions and incentives are targeted toward the actual service and contribution provided. As they say, if you build it (a market), they (suppliers) will come—and if you ask for something that is not exactly what you meant, you will get it. The ERCOT Board of Directors recently approved a redefinition of the set of ancillary services products to align with the grid's current and future needs while also staying agnostic to the technology of the

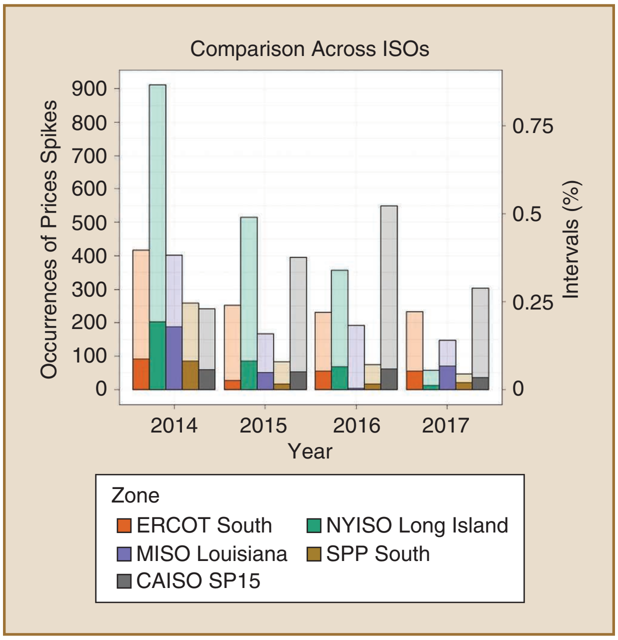

figure 4. The 5-min energy price spikes across U.S. markets. The dark colors indicate more than US$1,000/MWh; the light colors indicate more than US$500/MWh. ISO: independent system operator; MISO: Midcontinent ISO.

service provider (Figure 5). For example, it was proposed that the previous responsive reserve service (RRS) be disaggregated into two pieces. The first is a new RRS that applies only to the period directly after occurence of a contingency until frequency is stabilized but not corrected (e.g., 30 s). The second is the ERCOT contingency reserve services, which specifically covers the time after frequency is stabilized until the frequency and area control error have been corrected (e.g., 10 min). The new RRS is further split into FFR service (FFRS) and primary frequency response (PFR). FFRS is characterized by its ability to convert reserve capacity into energy or curtail energy consumption extremely quickly (15 cycles, a quarter of a second) and sustain that response for 15 min if needed. This allows the independent system operator to get what it truly needs (energy with little delay after a disturbance), rather than designing the product in only the traditional way around a conventional turbine governor. One final evolution is that the system requirements for many of these services are dependent on one another. For example, the requirement of how much RRS is needed depends on how much system inertia ERCOT has. In ERCOT's case, having more realistic service definitions that achieve system needs and characterizing these needs accurately offer the potential for incentives that continue to motivate sellers to provide a better service at lower cost.

European transmission system operators are also aware of the changes needed when large rotating mass units disappear from the grid. Even if there is no clear view of the services required in the future, there is a belief that technology will be up to the task. Considerable research and pilot projects have been conducted on FFR, synthetic inertia, and better use of demand and renewable energy sources in countries such as Ireland, Spain, Denmark, and Germany.

As the system shifts toward an increasingly inverter-connected fleet, there is an increased focus on developing incentive compatibility around system services across operational, planning, and investment time frames. However, certain services may be better suited than others for being procured through market frameworks. For example, inertia for interconnection frequency support can be provided throughout the

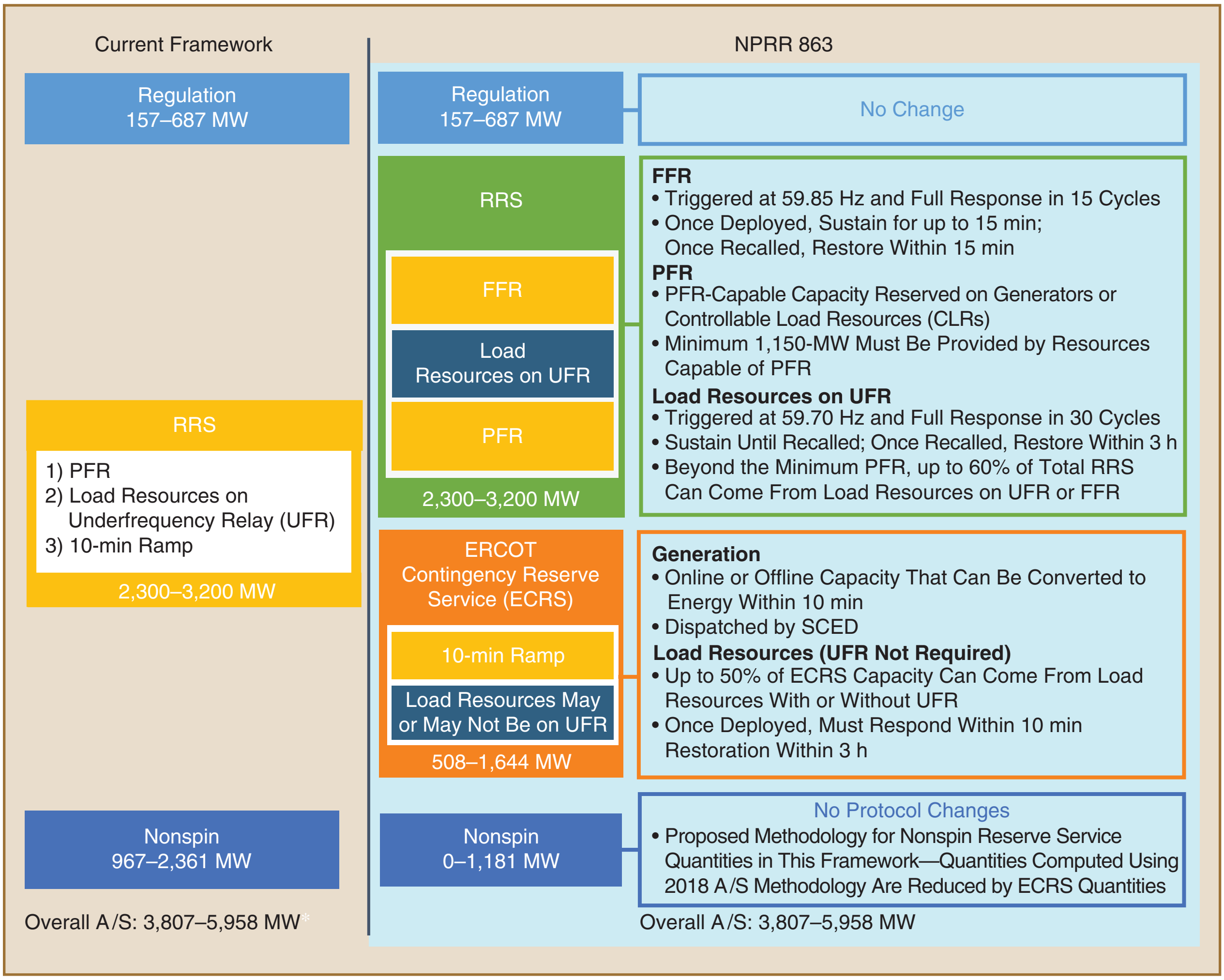

figure 5. The proposed ERCOT ancillary service framework changes. A/S: ancillary services; NPRR: Nodal Protocol Revision Request; SCED: security-constrained economic dispatch.

interconnection and transferred across ac links and has a degree of substitutability with FFR and PFR. By contrast, system strength and voltage control are highly locational issues, with specific contributors and little competition. As shown in Table 1, other characteristics of the system service may influence whether the market framework for that given service may be implemented, including complexity, overabundance in supply, or a situation in which economic benefits cannot justify the cost of administering the market. These characteristics should continue to be evaluated in the future, as some may not hold true for future scenarios with massive amounts of VRE.

Changing Structures and Shifting Market Paradigms

Will existing energy and reliability services markets be enough to provide the signals to get the resource fleet, dominated by VRE, to provide energy to where it is needed, when it is needed, and in a reliable manner? Today, some markets across the United States, Canada, and Europe have, or are introducing, plans for centralized capacity markets as a potential means to provide additional revenue to accommodate the missing money discussed previously and ensure that planning targets are achieved. Other financial markets are also part of the overall market design of many regions around the world for various reasons, including products like financial transmission rights and virtual trading. Will any of these designs be beneficial for a system that has hours during which nearly all energy is provided by renewables? Will additional products, auctions, or structural changes not yet tested be beneficial?

An important system need is energy at peak times. Modeling and experience suggest, even for those scenarios in which several hours are fully supplied by renewables, that there will be time periods when energy demand will greatly exceed the supply of renewable energy. A range of structures and designs that address how to pay for the resources needed to fill this gap are being debated. The market-design solutions are different depending on whose responsibility it is to procure those resources. In a decentralized procurement structure, where a system operator is limited to short-term operations, this responsibility falls on load-serving entities. In a central procurement structure, a central authority (e.g., a system operator or government entity) is assigned long-term energy responsibilities. A third model is "regulated generation," in which a vertically integrated utility is compelled to make all resource-planning decisions.

In a decentralized procurement model, load-serving entities procure needed resources. If they fail, they pay a high scarcity-based price or may not have load served. Regulators may choose to oversee physical supply by some or all load-serving entities. Regulators may choose to oversee whether load-serving entities are financially capable of procuring the supply needed to serve their load. A variety of hedge contracts can be used on a bilateral basis to help finance needed resources.

Other potential designs include reliability outage insurance and priority frameworks. Current scarcity-pricing frameworks allow for demand-side participation in wholesale markets, but many consumers have been hesitant to engage with it. With the growth of renewables and options for self-supply, there are new market-design models aimed to establish an operational demand curve for consumers. Through the concept of outage insurance, consumers pay a premium for the level of reliability coverage and compensation they seek. This would establish a priority scheme for reliability outages.

With Internet of Things-enabled devices becoming less expensive and more reliable, load-serving entities can sell energy at differing levels of reliability. Under scarcity conditions, the system operator, instead of curtailing load feeder by feeder, can curtail load on a customer or even on certain devices at a customer location, based on the service-reliability level of that load.

In Europe, there is much discussion on how to further reduce carbon emissions. Electrification is an important part of the solution but may be expensive if it is the only solution. Thus, any market design should take into account the interplay with other energy carriers (heat, hydrogen, natural gas, industrial, and so on). The emergence of both static and mobile storage will also be a challenge and an opportunity for the electricity market. Increased electric vehicle deployment offers the opportunity for co-optimization of transport and electricity services, such as vehicle-to-grid services. Innovative business models are already being observed, such as vehicles providing grid services in CAISO through its network of electric vehicle charging stations.

There is also a growing need need for much closer cooperation with distribution utilities and distribution system operators. Typically, transmission system operation has been linked to wholesale markets, whereas distribution systems have been linked to retail markets. With more suppliers coming from distribution systems and the ability to improve efficiency with consumer response to wholesale prices, the market structures may require changes and lines blurred. There have been proposals for all consumers to see the

table 1. The potential characteristics that may limit the market framework (illustrative only).

Reasons Why a Market Product May Not Be Implemented	Example
Product is too complex to design (e.g., software complexity).	Volt/var support
Product is too specific to certain local areas (little to no competition).	Volt/var support
System inherently has more than sufficient amounts of the service.	Synchronous inertia
Costs for the service may be small, so the expense of administrating the market product may outweigh the benefits.	Black-start (restoration) service
There is a specific resource requirement rather than a system-wide need.	Low-voltage ride-through

wholesale locational marginal price, even some in which that price reflects additional distribution system constraints and operation. Ensuring that these two systems operate without seams and that transmission and distribution system services are provided by whomever can provide them most efficiently will be crucial to the success of future market scenarios.

Other, more substantial, market structure changes have been proposed, such as configuration markets. This concept suggests that, in a scenario with massive renewables supplying energy, the revenues of energy markets may be insignificant with regard to incentivizing the needs of this future power grid. The characteristics that require incentives are investing in efficient configurations of renewables, flexible resources, and infrastructure to accommodate the needs of this future scenario. The configuration market would be conducted periodically (e.g., every five years) using optimization techniques to find the most efficient and feasible configuration. All participants that pass through the configuration market would be eligible to recover costs, as long as they meet established performance criteria. This design is similar to existing capacity markets that expand significantly to include attributes beyond capacity that may be needed on the system, while also including the infrastructure of the future grid to deliver power.

One additional structure change familiar to those who have been part of electric power systems for decades is the move back toward a fully regulated system. If the benefits of competition from these future power systems are not realized and monopolies of power supply and reliability services are seen as not preventable, a regulated system may be feasible. That does not make things any simpler; the way that the system is planned and operated would continue to be just as complex. The decisions, whether made by one entity or multiple parties, would use the same engineering and economic principles used for investments and operational strategies for this future resource fleet, which may look very different from what it does today, with poor decisions still resulting in inefficient or unreliable outcomes.

Summary

There has been a significant evolution in the world's electricity markets, just as there has been in their constituent technologies, operating procedures, and makeup. There are still many questions about how these markets may be structured to incentivize the investment and operational decisions that will lead to economic and reliable outcomes on very high VRE systems. There is no "one size fits all" in electricity market design, which is a recurring theme. There are many different future scenarios, including those that may lead to lower carbon emissions. A particular market design should not be chosen because of its scenario rather, the scenario should result because of the attributes, which were incentivized, and the least-cost solution, which emerged to satisfy those needs. There are many unknowns, including the continuing evolution of the policy environment and changing technologies, and many players need to work together to help manage this process to ensure a reliable and economical power system in the future.

For Further Reading

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