Designing Electricity Markets with Massive Amounts of Zero-Cost Variable Renewable Resources

Introduction

The increase in variable renewable energy (VRE) on the bulk power system can create both challenges and opportunities as described throughout this issue. Many regions across the world are starting to approach penetration percentages that were unprecedented during the initial introduction of organized wholesale electricity markets. However, 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. Of course, there are ongoing design enhancements being discussed throughout markets across the world that are experiencing increasing levels of renewables. Market operators can borrow design characteristics from each other, and also learn which designs may or may not work as well. However, as an industry, we are starting to look past these modestly high penetration percentages of VRE. We are starting to ponder the question, what would a market look like if the entire supply of energy for a particular market interval was supplied with 70, 80, 90, or 100% renewable resources?

In Europe, countries like Denmark, Ireland, Germany, and Spain have already seen hours of 138%, 88%, 89%, and 64% energy supplied by wind and solar (with Ireland being a single interconnection). In the U.S., 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. CAISO has served 93% of load from carbon-free resources, and Kansas has served 106% of load from wind, in a single hour. In South Australia, operated by the Australian Electricity Market Operator (AEMO), the amount of 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, but something for which these market operators need to prepare. If there are significant market design changes that 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 (see Lew et al, Matevosjana et al), variable renewables like 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, causing greater need for operational flexibility. To extract this flexibility, compensation must be available so that existing flexible resources have the incentive to provide flexibility, and that new, or modified, flexible resources have the incentive to build or retrofit with the needed flexibility. As most variable renewables are non-synchronous resources, there may be need for additional incentives to ensure that necessary attributes of synchronous resources are maintained or developed through other innovative ways.

Finally, as wind and solar do not have a cost to supply their natural fuel, their costs are entirely made up of capital and operations and maintenance costs. The majority of market designs across the world focus on marginal cost pricing and incentivizing for more efficient heat rates and lower fuel costs. 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 not one simple answer to the question of which one is best. The authors have no crystal ball, and acknowledge that the market design of any particular region is stakeholder- and regulator-driven. The authors also do not provide answers to the question of what a successful market design looks like. You will notice that most of this article is asking questions of readers of what may be expected and how markets may be able to provide for addressing the challenges faced with high levels of VRE. 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 potential scenarios.

Electricity markets to accommodate 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 of the more significant changes that have been introduced to date. In a previous article, written two years ago, a number of changes to the electricity markets were discussed. (See Ela et al. 2017) These include market expansion and coordination, phase out of priority dispatch support, new and evolving ancillary service products, designs for greater ramping capabilities, intra-day markets, and price formation changes. In this section, we will expand on recent design changes in a few regions experiencing high VRE levels .

The CAISO has made numerous changes to incentivize flexibility and ensure it is being provided. CAISO recently proposed to enhance its day-ahead market by moving from the current hourly granularity to a fifteen-minute granularity. Introducing fifteen-minute day-ahead intervals can better position the resources to accommodate net load ramps that occur in real-time by using more information on when those ramps may be occurring within the hour. Currently, the real-time market must dispatch resources to manage granularity differences between the hourly day-ahead market and the five-minute real-time market. 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 that prices in the day-ahead market are aligned with real-time when those greater ramps are expected.

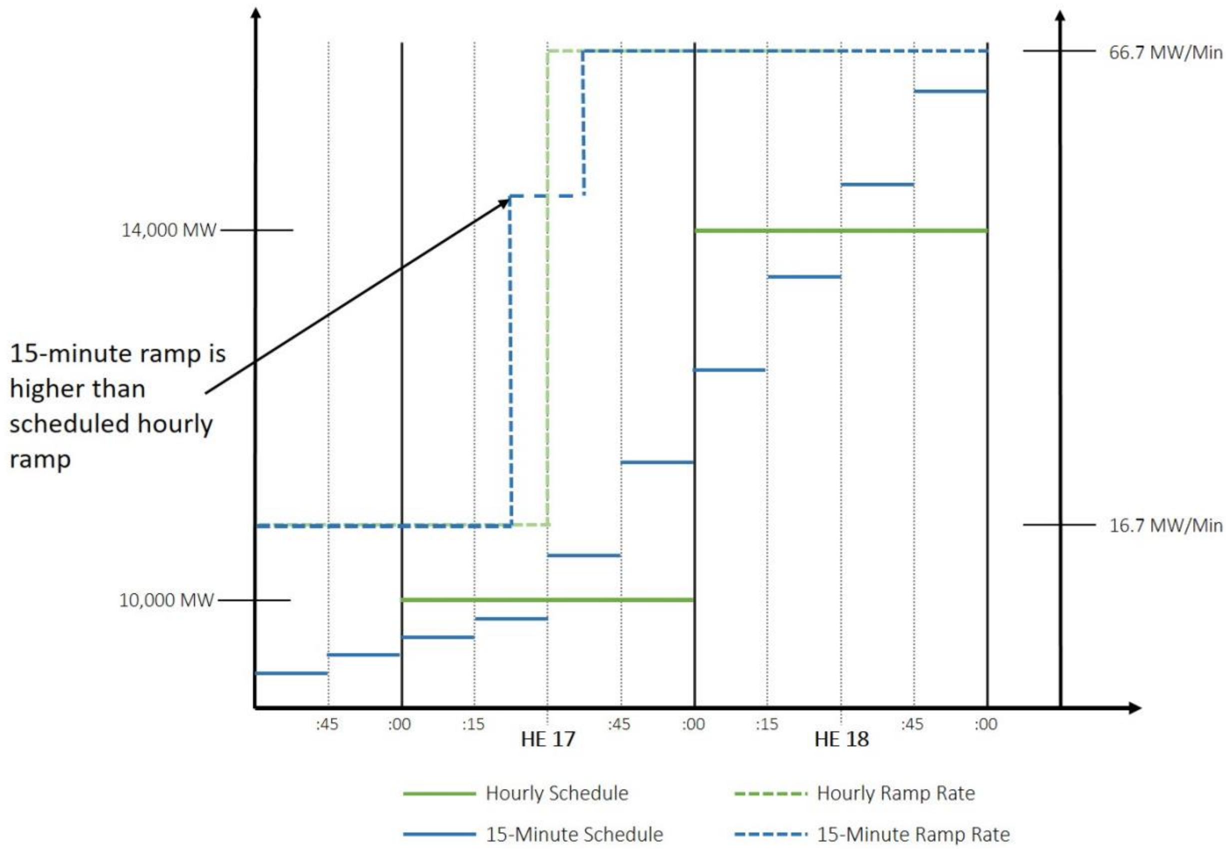

Figure 1 CAISO 15 minute to hourly day-ahead ramp comparison

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 provides an opportunity for VRE to participate in regulation down without having to curtail in advance. Evaluation of a ramping product is under way to provide incentives for ramping events that SPP experiences. SPP 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., greater than one hour). New products to ensure available ramping for different horizons has been observed now in several U.S. markets.

ERCOT is an “energy only” market, with no capacity market. It has seen declining planning reserve margin trends from a 2017 summer forecast of 9.4% to a recent 2019 summer forecast of 7.4% and a non-binding target of 13.75% (see Figure 2), which are the lowest of any region in the continental U.S. While this decline is not entirely due to renewable resources, the reduction of energy prices, which can be due both to 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) as a way 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 incent investment and thus increase the reserve margins to achieve goals of a long-term market equilibrium that is in line with target reliability reserve margins.

This is the author's version of an article that has been published in this journal. Changes were made to this version by the publisher prior to publication.
The final version of record is available at http://dx.doi.org/10.1109/MPE.2019.2933281

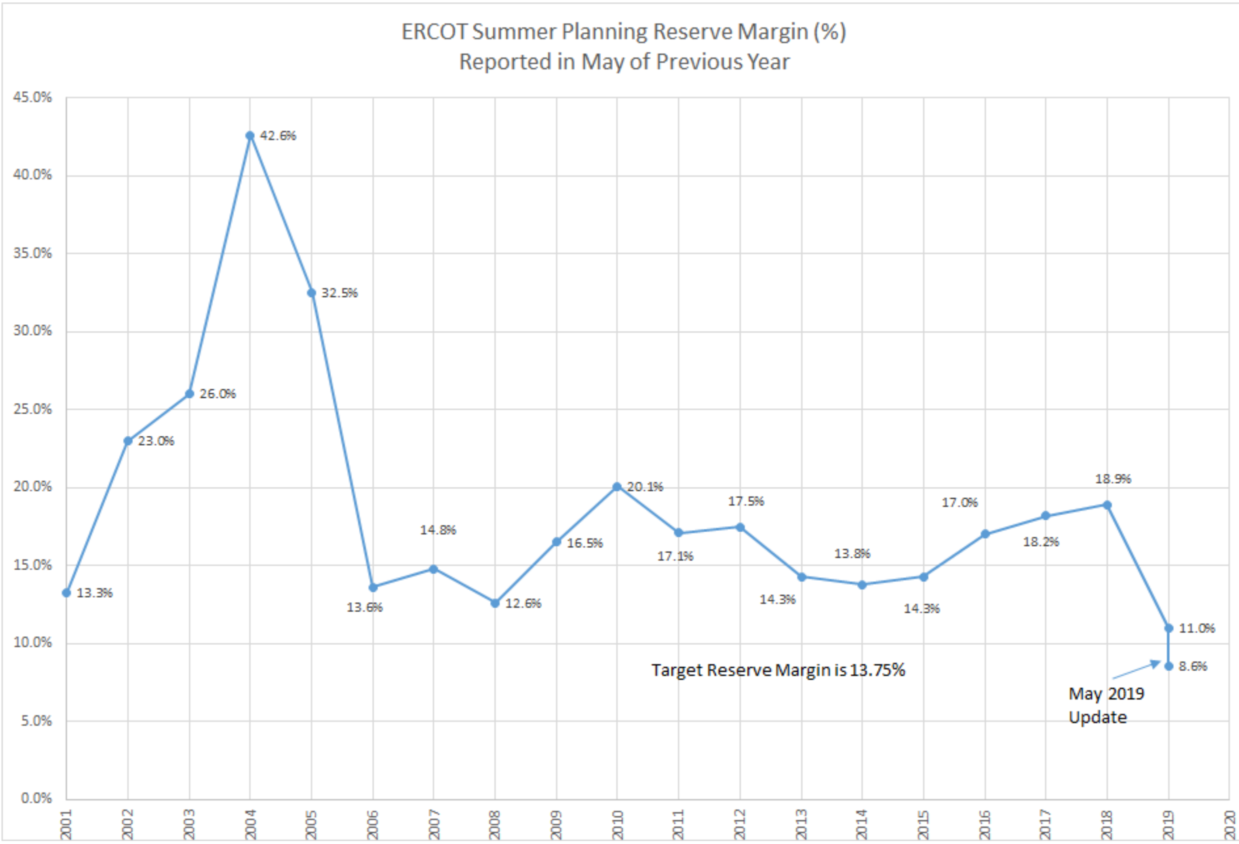

Figure 2 ERCOT Reserve Margins have fallen dramatically.

Europe has developed a set of rules and guidelines in order to harmonize day-ahead, intraday and balancing markets across regions to enable cross-border trade on interconnectors in all these timeframes. 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 intra-day markets. It has an explicit market-wide Capacity Mechanism to incentivize availability at peak times. Significant work has also been done reinventing an appropriate System Services procurement framework to allow for provision of services from any technology. This framework has facilitated a fundamental transformation of the capability of existing plants, including a reduction of more than 400 MW in minimum generation limits, incentives for demand management, and allowance for wind providing operating reserves. The revised framework has incentivized sufficient capability to manage instantaneous penetrations of up to 75% of non-synchronous technologies. Augmenting this System Services framework further to facilitate over 95% instantaneous penetration of VRE is seen as essential in meeting the Ireland government target of 70% annual renewable supply by 2030.

Australia has observed increasing interventions in the market for the purposes of maintaining system security. Over 2018, the AEMO has 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. Non-synchronous generation (primarily wind) has also been curtailed for the purposes of maintaining system strength. This emphasizes the importance of having a market design that fully incorporates the full suite of technical requirements that are critical for operating a complex electrical system.

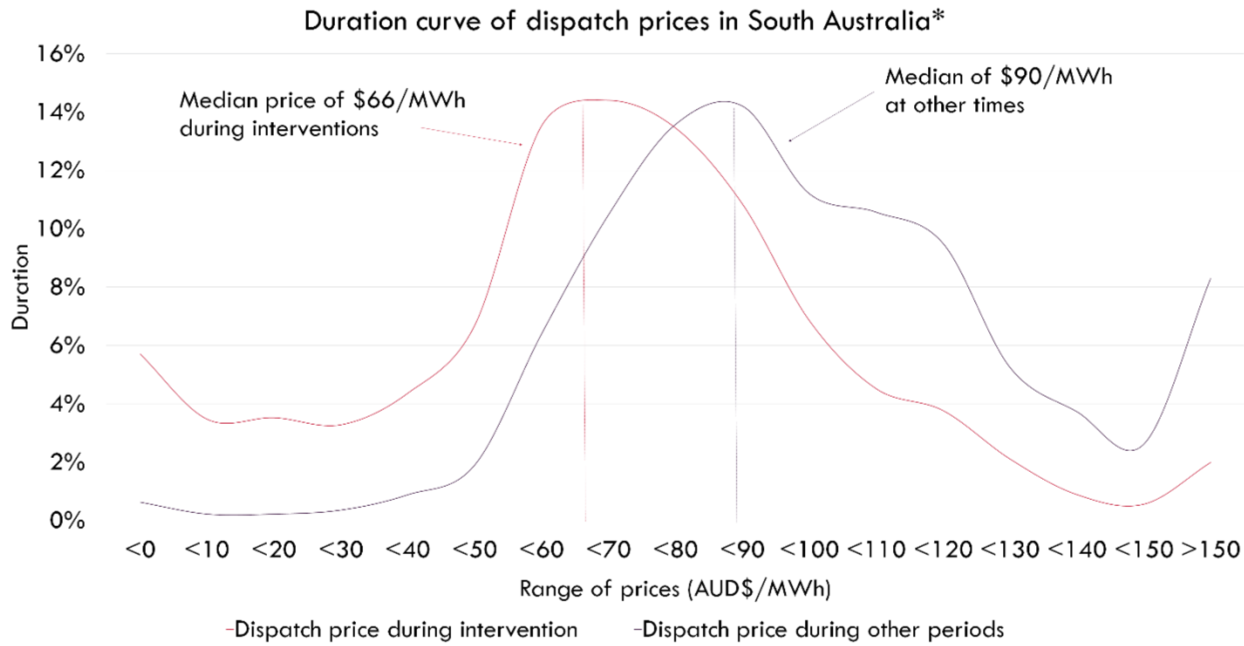

Figure 3. Duration curve of prices during system directions in Australia.

Electricity Markets of the Future: Will it require large redesigns or a few tweaks?

The primary question being asked is how significant the design changes may need to be to enable a market with nearly full supply of renewable energy. While many electricity markets are designed to align with the physics of electricity generation and delivery, the existing designs differ across the globe. Will these existing designs continue to provide the right incentives for industry to provide reliable and affordable power? Will continued tweaks be necessary to accommodate the changing characteristics? Or will the industry see large restructuring efforts, where the existing designs are just no longer feasible given the substantial changes to what is needed to supply this much energy from resources with the characteristics described. The authors do not have the answer to these questions, but provide insights on where some of the discussion has been to date.

While the market designs differ across the globe, most regions have a central focus on prices that are based on marginal operating costs to supply energy. By reducing the cost to supply energy, typically through heat rate improvements and fuel cost reductions on thermal plants, the participant gains more profit when the cost of the marginal providers is unchanged. On 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 behavior should a market incentivize on this future system? A few of the possible characteristics that might be desired include the following:

- Lower costs for capital, operations, and maintenance
- Locate supply where energy can be delivered to where it is needed and reducing the infrastructure (e.g., transmission) costs
- Provide the most energy per installed unit of capacity (increase capacity factors, which is similar to lowering capital costs)
- Reduce the impact of variability and uncertainty and potential for load shedding or other reliability consequences
- Provide sufficient reliability services
- Demand side participation

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

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. Markets in the United States use locational marginal pricing for every generator node on the system, with centralized unit commitment and economic dispatch, and prices that often include three-part offer costs (start-up cost, minimum-load costs, and energy offer curve). European markets typically have zonal prices with decentralized unit commitment and single-part offers (start-up and no-load must be included in the single offer). In markets like ERCOT and AEMO, the revenues from the energy market and reliability services market are the only revenues available, while others have capacity payments of some form. While there have been some substantial changes, not many of these changes are primarily 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 withdrew due to insufficient revenue were still needed by the grid operator for various reasons, it is possible that the design of the market is flawed and needs modification. In existing designs when this happens, out-of-market actions may take place.

While lower energy prices are anticipated on higher renewable systems, it is not necessarily a proven fact in all cases. When the system is at a greater risk, prices are today set by administrative “shortage” prices, values that often exceed $1,000/MWh in the U.S. 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 market operators adjust the set of conditions in which these prices trigger, the overall average energy price may not necessarily be lower. With the existing market design, you could see 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 shortage conditions rather than exceeds them. Alternatively, consumers can set those shortage prices rather than the administrative values that are set by the market operator (with agreement of stakeholders and regulatory agencies). As can be seen in Figure 4, there is no clear trend yet observed on increasing shortage pricing due to increased renewables. However, in some regions such as CAISO, shortages are often being triggered by a lack of ramp available during the evening (when load picks up and solar PV 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 how demand may play a more defined role during these conditions.

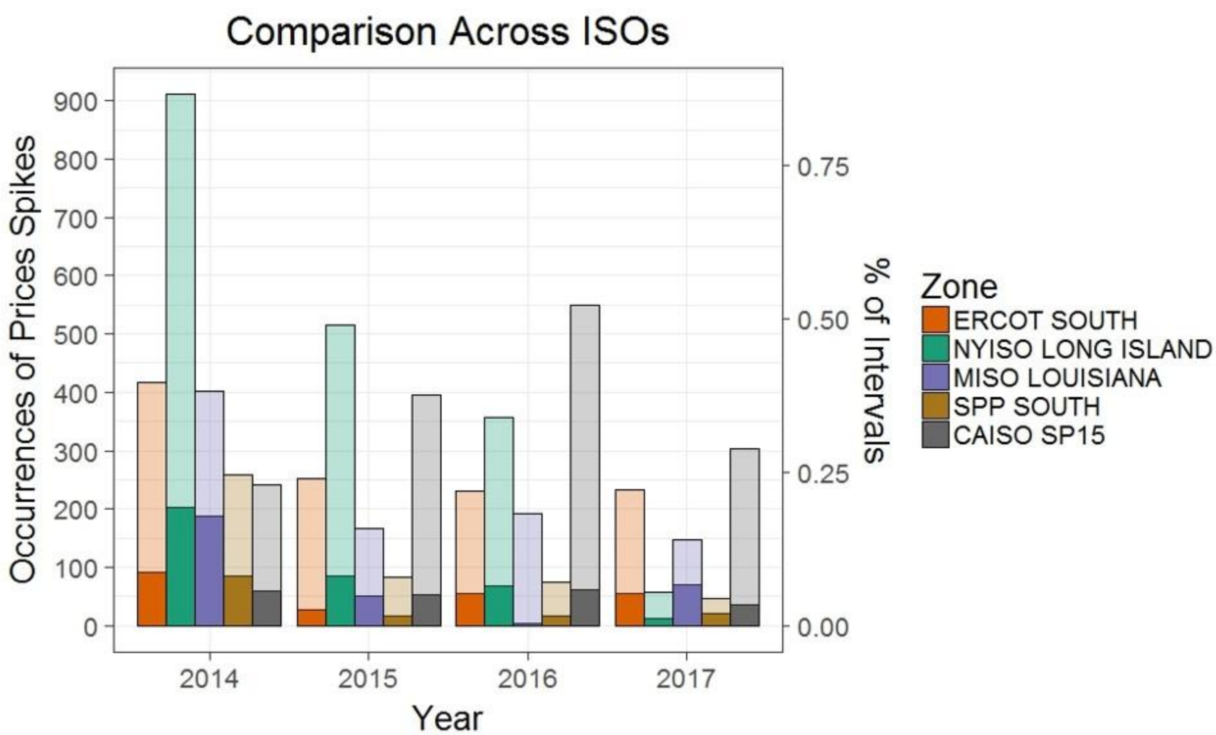

Figure 4. Five-minute energy price spikes across U.S. markets (dark: over $1000/MWh; light over $500/MWh).

Traditional approaches to Demand Response (DR) have focused mainly 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, where incentives are provided to behind the meter technologies to consume excess renewable energy and supply it back at times when it is needed.

There are questions on 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. Additionally, as VRE forecasting errors tend to reduce significantly as we approach real-time, would this reduce the benefits of day-ahead markets that increasingly deviate from real-time conditions. Europe has observed shifts away from day ahead markets towards intra-day and real time markets. Do 'ahead' markets need to be more responsive to the forecasting timeframes 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 on 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, while 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 these markets, while crucially providing the incentives to ensure a reliable electric system, are somewhat of an afterthought when considering the small amount of revenue that is 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 reliability services due to the lower energy prices, revenues from reliability service markets may possibly become greater proportion of overall revenue sources. However, if the service is abundant and can be provided cheaply, this condition 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, 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 across different markets. Some definitions are somewhat archaic, others based on existing characteristics other than explicit needs, and still others may aggregate multiple services as one to make things simpler. The first

This is the author's version of an article that has been published in this journal. Changes were made to this version by the publisher prior to publication.
The final version of record is available at http://dx.doi.org/10.1109/MPE.2019.2933281

step may be to ensure the definitions and incentives are targeted towards the actual service and contribution that would be 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 current and future needs of the grid while also staying agnostic to the technology of the service provider (Figure 5). For example, the previous Responsive Reserve Service (RRS) is proposed to be disaggregated into two pieces. The first is a new RRS, which only applies tot the period directly after occurence of a contingency until frequency is stabilized but not corrected (e.g., 30 seconds). The second is the ERCOT Contingency Reserve Services (ECRS), a service that specifically covers the time after frequency is stabilized until the frequency and area control error have been corrected (e.g., 10 minutes). The new RRS is further split into Fast Frequency Response 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, quarter of a second), and sustain that response for 15 minutes if needed. This allows the ISO 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 is dependent on how much system inertia ERCOT has. In ERCOT's case, having more realistic service definitions that achieve system needs, and characterizing the system needs in an accurate manner, has the potential to lead to incentives that continue to motivate sellers to provide a better service at lower cost.

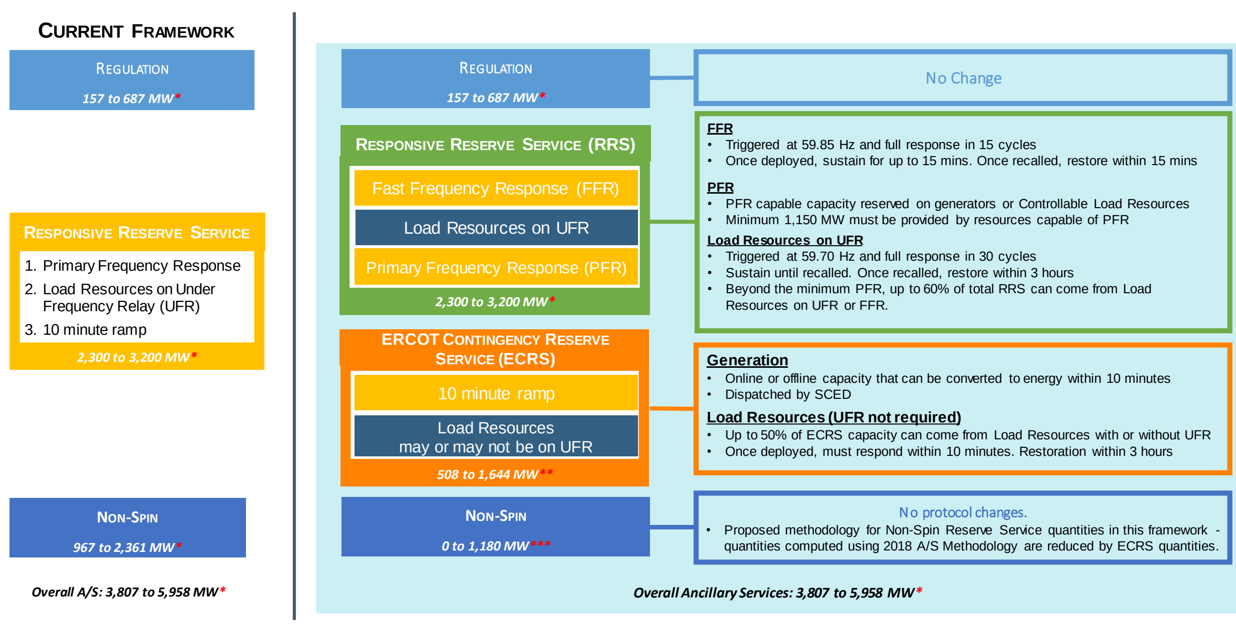

Figure 5. Proposed ERCOT ancillary service framework changes.

European TSOs are also aware of the changes needed when big rotating mass units disappear from the grid. Even if there is no clear view of the required services in the future, there is a belief that technology will be up to the task. Considerable research and pilot projects have been conducted on fast frequency response, synthetic inertia, and better use of demand and renewable energy sources (RES) in countries like Ireland, Spain, Denmark and Germany.

As the system shifts towards an increasingly inverter-connected fleet, there is an increased focus to develop incentive compatibility around system services across operational, planning, and investment timeframes. 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 interconnection and transferred across AC links and has a degree of substitutability with fast-frequency response and primary frequency response. By contrast, system strength and voltage control are highly locational issues, with specific contributors and little competition to contribute. 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 when the economic benefits cannot justify the cost of administering the market. These characteristics should continue to be evaluated in the future, as some of the characteristics may not hold true for future scenarios with massive amounts of VRE.

Reasons why a market product may not be implemented	Example
Too complex to design (e.g., software complexity)	Volt/VAR support
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 cost of administrating market product may outweigh benefits	Black start (restoration) service
A specific resource requirement rather than a system-wide need	Low Voltage Ride Through

Table 1 Potential characteristics that may limit market framework (illustrative only).

Changing Structures and Market Paradigm Shifts

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 in a reliable manner? Today, markets across the U.S., Canada, and Europe have in place or are introducing plans for capacity markets to provide additional revenue to accommodate the missing money discussed earlier, and to ensure planning targets are achieved. Other financial markets include financial transmission rights and virtual trading. Will any of these designs be beneficial for a system that has hours where nearly all energy is provided by renewables? Will additional products, auctions, or structural changes that have not been tested yet be beneficial?

An important system need is energy at peak times. Modeling and experience suggest, even for those scenarios where several hours are fully supplied by renewables, there will be periods of time in which energy demand will greatly exceed supply of renewable energy. A range of structures and designs on 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 “de-centralized 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” where a vertically integrated utility is compelled to make all resource planning decisions.

In a de-centralized procurement model, load-serving entities procure resources needed. 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 financial capabilities of load-serving entities to procure 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 heretofore been hesitant to engage with it. With the growth of renewables and options for self-supply, there are new market design models that aim 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 the Internet of Things (IOT) 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 reliability service 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 the only solution. Thus, any market design should take into account the interplay with other energy carriers (heat, hydrogen, natural gas, industrial, etc.). 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 the provision of vehicle-to-grid services. Innovative business models are already being observed, such as vehicles providing grid services in CAISO through its network of EV charging stations.

A need for much closer cooperation with distribution utilities and distribution system operators is also a growing need. Typically, transmission system operation has been linked to wholesale markets, while distribution systems have been linked to retail markets. With more suppliers coming from distribution systems and with the ability to improve efficiency with consumer response to wholesale prices, the market structures may require changes and the lines may become blurred. There have been proposals for all consumers to see the wholesale locational marginal price, and even some where that price is reflective of additional distribution system constraints and operation. How to ensure that these two systems operate without seams, and that both 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. Researchers have proposed “configuration markets”. The concept behind this design is that the revenues of energy markets in a scenario with massive renewables supplying energy will be insignificant with regards to incentivizing the needs of a future power grid. The characteristics that require incentives are investment 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 can be considered 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 to where it is needed.

One additional structure that is no stranger to those that have been part of electric power systems for decades is moving back towards 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 a feasible option. That doesn't 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 as the 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 significant evolution in the world's electricity markets, just as there is in their constituent technologies, operating procedures, and makeup. There are still many questions on 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 low carbon futures. A particular market design should not be chosen because of a particular 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 the changing technologies, and there are many players that need to work together to help manage this evolutionary process to ensure a reliable and economical power system in the future.

For Further Reading

E. Ela et al., "Electricity Markets and Renewables: A Survey of Potential Design Changes and Their Consequences," *IEEE Power and Energy Magazine,* 15 (6), Nov/Dec. 2017.

M. Goggin, R. Gramlich et al., *Focused and Clean: Power Markets for the Future*, 2018.

B. Gerke et al., *Shift Demand Response: A Primer,* Lawrence Berkely National Laboratory, 2018.

Evaluation of Wholesale Energy Price Spikes in U.S. Electricity Markets, 2018, EPRI, Palo Alto, CA: 3002013886.

S. Newell et al., "Cost-benefit analysis of ERCOT's Future Ancillary Services (FAS) Proposal," Prepared for Electric Reliability Council of Texas. December 2015.

S. Corneli et al., *Wholesale Electricity Market Design for Rapid Decarbonization: Long-term markets, working with short-term energy markets,* Energy Innovation.org. June 2019.

Authors

Erik Ela is with the Electric Power Research Institute

Farhad Billimoria is with the Australian Electricity Market Operator

Kenneth Ragsdale is with the Electric Reliability Council of Texas

Sai Moorty is with the Electric Reliability Council of Texas

Jon O'Sullivan is with Eirgrid

Rob Gramlich is with Grid Strategies LLC

Mark Rothleder is with the California Independent System Operator

Bruce Rew is with the Southwest Power Pool

Matti Supponen is with European Commission (retired)

Paul Sotkiewicz is with ECubed Policy Associates