**Title**
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**Journal**
IEEE Power and Energy Magazine, 19(1)

**ISSN**
1540-7977

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**Publication Date**
2021

**DOI**
10.1109/MPE.2020.3033396

# Electricty Market of the Future: Potential North American Designs Without Fuel Costs

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ELECTRICITY MARKETS IN THE UNITED STATES and Canada have evolved since their inception in the late 1990s and early 2000s. Not all states and provinces moved toward restructured organized electricity markets, but rather those that have belonged to markets operated by independent system operators (ISOs) and regional transmission organizations, with designs developed through stakeholder processes and approved through state, provincial, or federal agencies, such as the Federal Energy Regulatory Commission (FERC).

Areas in the western United States are also beginning to join organized markets. Differences in design exist due to regional characteristics and stakeholder processes, but most continue to converge to a common set of design features: locational prices based on marginal costs, bid-based security-constrained economic dispatch, and day-ahead and real-time auctions for energy co-optimized with ancillary services for common grid services. A question that often comes up is whether these market designs are sufficient for systems dominated by resources lacking fuel costs and possessing other unique characteristics or whether substantial changes may be necessary to ensure economic efficiency and reliability.

States, utilities, and companies have introduced mandates or goals to supply 100% of energy by renewable resources or nonemitting resources. (See Figure 1.) As of early May 2020, 16 states have adopted 100% clean/renewable mandates or targets, and more have adopted less-stringent goals. Finally, many of the organized markets are already experiencing high levels of instantaneous amounts of variable renewable energy (VRE), such as wind and solar. These experiences demonstrate that studying power systems with 100% zero-fuel-cost supply is not an academic exercise. Efficiently designed electricity markets can enable solutions to meet these goals while providing affordable and reliable electricity to consumers.

In this article, the authors discuss some key challenges and potential options for designing electricity markets when the supply fleet lacks fuel costs. This includes the transition to meet these goals as well as the designs incentivizing the investment in and operation of the future supply fleet. Before describing potential future designs, it is important to highlight current efforts to overcome challenges and improve market designs.

## Key Questions Facing Market Designers

With decarbonization goals, the future supply fleet may look quite different from the current one. It may consist of substantial amounts of VRE and hydropower, other enabling technologies like short-term or seasonal electric storage, greater levels of responsive demand, and local resources of numerous technology types (either on the distribution system or customer sited). It may also consist of other low-carbon resources like nuclear power and some remaining efficient thermal plants. Except for some remaining fuel-burning technologies, the future and current supply fleets will have something in common: variable operating costs that are not dependent on fuel costs.

At the core of any future scenario is VRE. VRE has several unique characteristics that are important to consider, given the quantities of VRE that may be present in these scenarios. VRE production depends on the weather, meaning that the available energy changes across time and cannot be predicted with perfect accuracy. VRE also has other unique technical characteristics, such as its inverter-based interface. Finally, because VRE depends on the weather for production, it has essentially zero variable costs, with most of its costs tied to capital. Each of these characteristics may influence future electricity market outcomes in different ways.

Similar to other commodities, wholesale electricity prices indicate when supply is limited and demand reduction is most valuable (high-price periods) or when supply is abundant and increased demand can be met with little additional cost (low-price periods). These wholesale pricing signals provide a coordinating role across various decisions, both for short-run operational decisions and long-run investment and retirement decisions. In recent years, the dominant driver of annual changes in average wholesale electricity prices has been natural gas prices, as natural gas generators have been the predominant price-setting technology. Over the past decade, the boom in U.S. shale gas production has driven prices well below their historical averages.

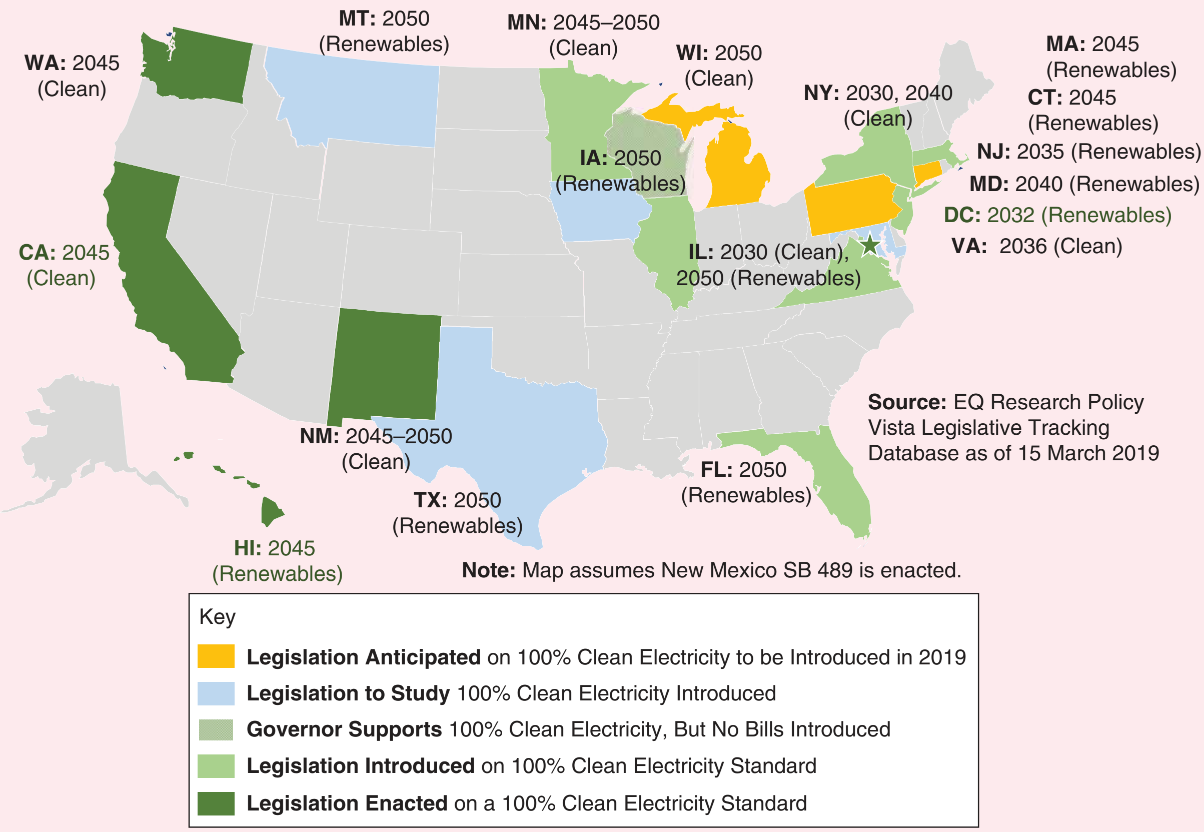
Growth in VRE is starting to have noticeable effects on wholesale electricity prices. VRE's lack of fuel costs pushes the supply curve out during periods of high VRE production. Without corresponding growth in demand or the retirement of surplus capacity, this results in the merit-order effect, that is, lower electricity prices. It also can lead to more variable prices across time and space as well as impacts on the prices of ancillary services, depending on conditions. However, the true impact on prices is not always simple to understand or predict.

The impacts of increased solar production on price patterns are obvious in the California ISO (CAISO), where solar produced more than 18% of annual demand in 2019. This has contributed to lower prices during midday, particularly in spring, but also pushes high-priced periods into the early evening after sunset. Thermal resources that are decommitted during midday may find it more difficult to supply energy after sunset because of commitment constraints. These temporal patterns and variability effects of prices can incentivize increased flexibility from both the supply and demand sides. The springtime supply abundance can also impact the ability to provide downward reserves from resources that are required to be online and generating above a minimum level. Thus, reductions in energy prices can simultaneously occur with increases in downward reserve prices (Figure 2).

Lawrence Berkeley National Labs has performed several simulations of market prices in futures with higher VRE penetrations for various U.S. regions, which show similar trends as the historic declining price impacts. Higher VRE levels were observed to lower average energy prices, increase price variability, increase the frequency of zero-energy prices, and increase prices for ancillary services. A variety of other studies have shown a range of wholesale price impacts from VRE, using a variety of different assumptions affecting the results (Table 1). The range in values demonstrates the difficulty in trying to predict this impact.

Although these simulations show a reduction in average energy prices due to increased VRE, this may not necessarily be the case on future systems approaching 100% renewable energy. Several assumptions in these studies may not always hold in practice. It is not clear that wholesale prices will simply decline, as observed in studies. This may depend on many factors, such as

- ✔ the market structure, including compensation and investment incentives beyond energy markets (e.g., capacity markets)
- ✔ exogenous planning reserve margins
- ✔ outside policies influencing investment
- ✔ responsiveness of demand to price
- ✔ the existence and settings of administrative shortage pricing
- ✔ VRE locations and the correlation of production




(a)


(b)

**figure 1.** U.S. goals for (a) states and (b) utilities (representative examples). (Continued)

- ✔ the cost-effectiveness and ability of enabling technologies that mitigate temporal supply and demand concentrations.

Other questions have piqued the interest of market designers. If electricity markets do not incentivize resources for supplying emission-free energy, how would the resource mix transition to the scenarios being discussed? If the transition is supported outside of electricity markets, how will this impact optimal solutions? If the variability of VRE increases the need for flexibility, will the markets incentivize those attributes? How important will future ancillary service markets be? Will VRE variability increase price volatility, or will enabling resources take advantage and reduce the variability? Will VRE forecast errors cause greater uncertainty of prices and divergence between day-ahead and real-time markets? Will unit commitment procedures be necessary, or, if not, how must the market clearing models be enhanced? How will transmission flows and congestion price hedging be impacted if increased variability is present? How will growing amounts of small resources, either residentially owned or located on distribution systems, compete in wholesale markets? Finally, will wholesale and retail designs enable consumers to react to prices in meaningful ways? These are some of the many questions that market designers must consider when evaluating how markets may evolve to allow for an economic, reliable, and environmentally responsible electric power system.

## What Does a Future Market Design Need to Do?

Today, marginal cost pricing provides several benefits. It incentivizes resources to use low-cost fuels and improve heat-rate efficiency to generate more energy per unit of fuel consumed. It also provides rents for resources that are inframarginal. Locational pricing motivates suppliers to build in areas with the highest value. Ancillary service co-optimization prompts resources to provide services that are most valuable to the grid at the least cost. Lastly, designs such as shortage pricing primarily incentivize resources to provide energy and services at critical time periods. Many of these attributes will remain important in the future system, but some may be less significant. For example, there may not be fuel to procure

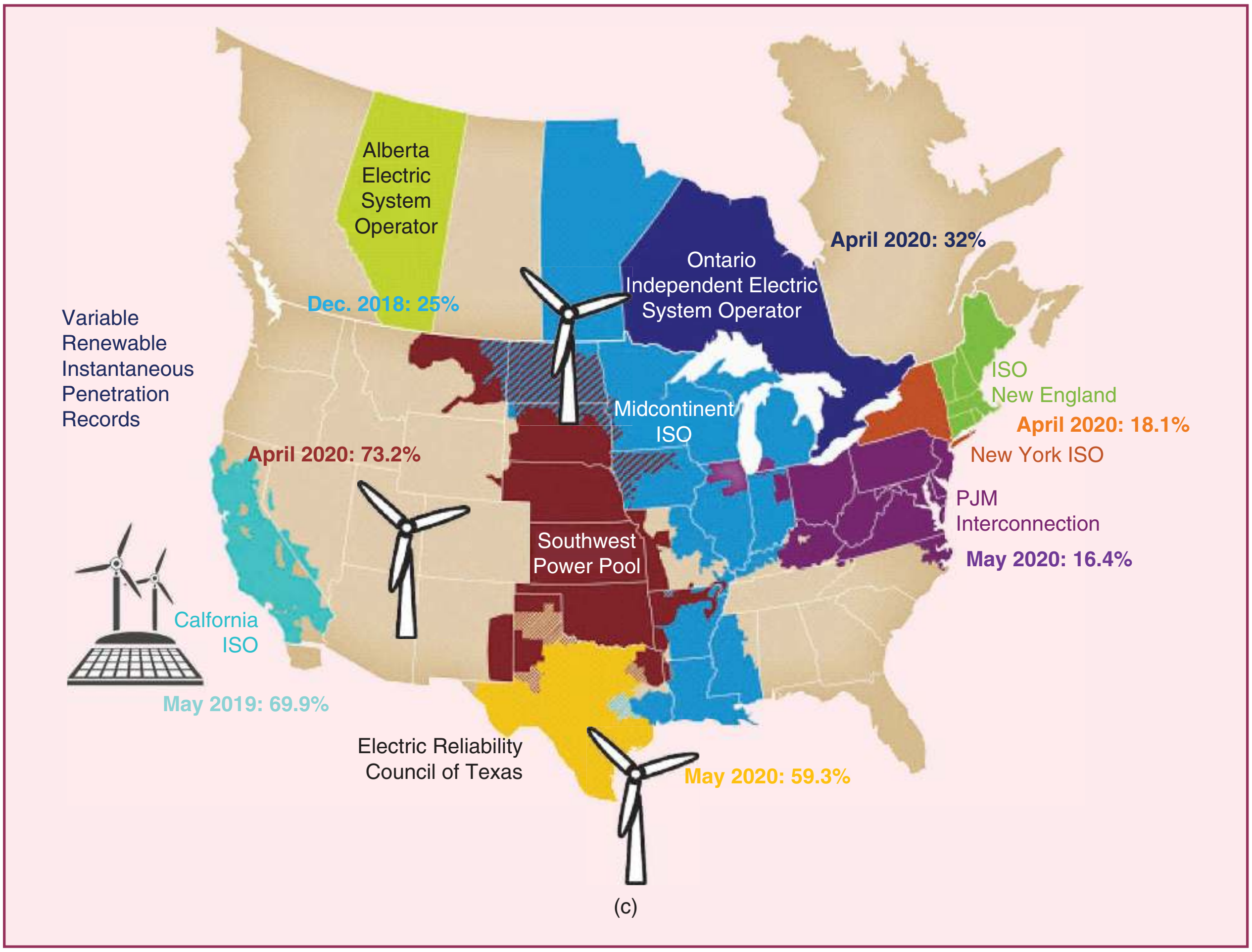



**figure 1.** (Continued) U.S. goals for (c) The most recent instantaneous VRE penetration records. Data are accurate as of September 2020. (Source: Electric Power Research Institute and Energy Systems Integration Group; used with permission.)

nor heat rates to make efficient. Unit commitment costs may be negligible, and installed capacity may not be the primary attribute signifying supply adequacy. Many participants may bid into the market based not on fuel costs but on opportunity costs. For example, the opportunity cost of demand-side resources is based on forgoing or shifting consumption, and the opportunity cost of energy-limited resources is based on the potential lost profit if energy produced cannot be sold later due to lack of energy stored. Moreover, price signals may be needed to incentivize attributes or behaviors that are abundant today but may become crucial and in short supply in the future.

At the onset of electricity sector restructuring, market designers considered what markets should be signaling. This is as important now as it was then, and while the resource mix is changing dramatically, the principles are mostly unchanged. A research team led by Energy Innovation, an energy policy research firm, recently evaluated possible options for future electricity market designs. The team established 10 key principles for wholesale electricity markets, which ensure economic efficiency, reliability, and technology neutrality. The Energy Systems Integration Group (ESIG) also held a workshop "toward 100%," with six important tracks on key challenges. One of those tracks was on future markets, where the participants discussed key challenges and potential strategies. Numerous ISOs and regional transmission organizations in North America have also authored studies and reports looking at future resource mixes with very high VRE, including New York Independent System Operator (NYISO), Southwest Power Pool (SPP), and others.

The Energy Innovation team established that wholesale electricity markets should do the following:

1) accommodate rapid decarbonization, providing opportunities for the participation of zero-carbon resources


**figure 2.** Trends in the (a) net load, (b) energy prices, and (c) downward regulation reserve prices in the CAISO, which reflect the impact of increased solar.

2) support grid reliability so that the incremental costs of reliability do not exceed 1) the amount customers would knowingly be willing to pay or 2) incremental benefits
3) promote short-run efficiency through the optimized dispatch of the lowest-cost resource mix
4) facilitate demand-side participation and grid flexibility
5) promote long-run efficiency, including efficient, competitive entry into and exit from the market, under conditions of significant uncertainty
6) minimize the exercise of market power and manipulation
7) minimize the potential for distortions and interventions that would prevent or limit markets' ability to achieve efficient outcomes, consistent with the public interest
8) enable the adequate financing of resources needed to deliver cost-effective reliability based on the efficient allocation of risk (i.e., those that can best mitigate risk should bear it), preventing customers from bearing the cost of poor investment decisions
9) be capable of integrating new technology as needs evolve, adapting as technology changes
10) have designs that are readily and realistically implementable.

Three broad philosophies stem from these principles. First, real-time prices should indicate reliability needs and incremental changes in supply and demand in the most granular way possible. Second, a market must transform physical system risk shared by all into fiscal risk shared out proportionally (no free riders/no market manipulation). Energy markets should aim to be able to manage as many situations as possible by raising or lowering prices. Finally, the market should be investable. The market must provide sufficient revenue to attract investment in assets that improve reliability or economic efficiency and promote the orderly retirement of costly, inefficient resources that are no longer needed.

The markets track of the ESIG workshop developed 20 questions requiring further examination. The track discussed key challenges and explored two exercises to see whether the solutions differ: designing markets for 1) a system that is 100% renewable and whose market could be designed from scratch or 2) a system still in the process of transitioning to 100% renewable. Topics ranged from how and what reliability services need to be incentivized to how an optimal resource mix can be attained. Price-responsive demand was a key enabler in all the discussions. With it, the group found the challenges easier to address, but without it, the challenges were difficult to overcome. Given the lack of fuel costs, the following behaviors and attributes, which may need signals to incentivise them, were highlighted:

- ✔ reducing fixed, capital, and operations and maintenance costs
- ✔ locating resources where they provide value and with the least overall cost, including infrastructure
- ✔ locating resources where they can provide the most energy without severely impacting reliability
- ✔ reducing the negative effects of forecast errors
- ✔ providing the most important reliability services at times when they are most needed
- ✔ transferring energy from times of ample supply to periods where supply is needed
- ✔ consuming energy at times when the cost to do so is acceptable and reducing consumption when it is not.

**table 1. The change in average wholesale electricity price and the VRE penetration increase for several recent studies in the United States.**

| Study | Market Region | Change in Price (US$/MWh) per Percentage Increase in VRE Penetration |
|---|---|---|
| Brancucci Martinez-Anido et al. (2016) | ISO New England | $–0.15 |
| Deetjen et al. (2016) | ERCOT | $–0.25 |
| EnerNex (2010) | Eastern Interconnection | $–0.45 |
| Fagan et al. (2012) | Midcontinent ISO | $–0.28 |
| GE Energy (2014) | PJM | $–0.50 |
| LCG Consulting (2016) | ERCOT | $–0.52 |
| Levin and Botterud (2015) | ERCOT | $–0.41 |
| Mills and Wiser (2012)—Solar | CAISO | $–0.13 |
| Mills and Wiser (2012)—Wind | CAISO | $–0.10 |
| New England States Commission on Electricity (2017) | ISO New England | $–0.80 |
| New York ISO (2010) | NYISO | $–0.45 |

ERCOT: Electric Reliability Council of Texas.

## Market Operators Are Adapting Now to Prepare for the Transition

In the United States and Canada, many organized markets are already observing high VRE levels. In the early morning of 27 April 2020, the SPP reached more than 73% of its instantaneous power provided by VRE. Many regions also have the challenge of market designs that must harmonize with policy decisions made outside of the market. Thus, market operators across the continent have been facilitating design changes to enable new technologies to participate, ensure reliability in the face of emerging challenges, and provide signals that lead to optimal operation and investment of the supply fleet.

### *95% Zero-Carbon Energy Production in Ontario*

In the span of 10 years, Ontario transformed its supply mix to produce 95% of its energy carbon free by phasing out coal resources from 2005 through 2014. The existing capacity from nuclear and hydro largely remained, while coal was replaced by natural gas, wind, and solar. The electricity market operated fundamentally in the same manner throughout this transformation using bid-based economic dispatch. Transmission-connected VRE was required to be dispatchable and bid into the market. As more VRE capacity connected to the system, electricity prices trended lower, demonstrating the merit-order effect, as discussed previously (see Figure 3). Recent prices have been, on average, one-third of the levels cleared from the market before the start of phasing out coal.

This transition has not resulted in binary market pricing outcomes of either zero dollars when VRE is marginal or a large spike when natural gas resources are. Ontario has a unique combination of zero-carbon resources in its hydro fleet that, while having no fuel costs, does have other imposed variable costs due to its dependency on water conditions. These prices range from negative values, representing costs incurred with non-production, to hundreds of dollars per megawatt, indicating limited water availability and opportunity costs. This is in comparison to natural gas fuel costs ranging in the tens of dollars to produce a megawatt hour of energy. The hydro portion of the supply curve has been preserved but shifted by the addition of VRE. For Ontario, the market design in place has been sufficient to efficiently dispatch the new supply mix. The variability and uncertainty of VRE resulted in greater price volatility, demonstrating the increased need for system flexibility and other products.

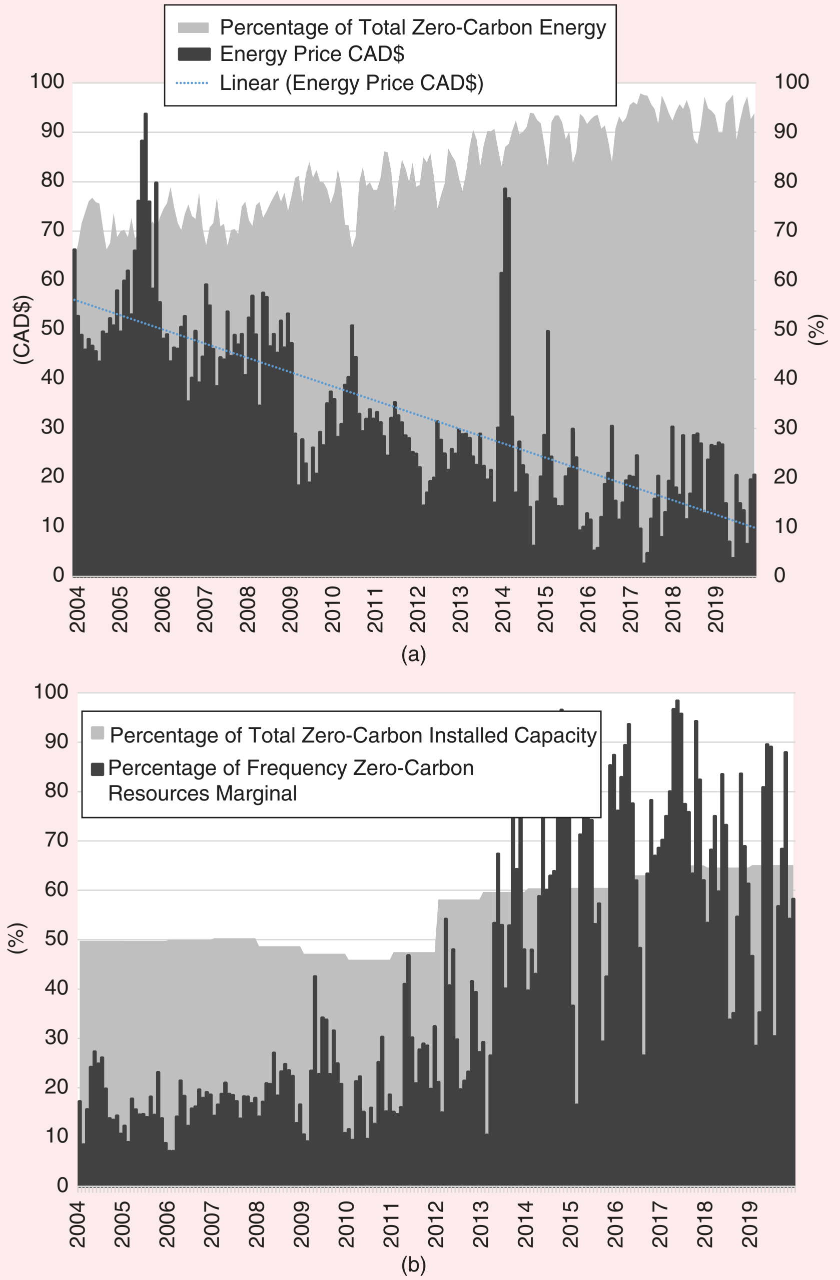



**figure 3.** (a) The merit-order effect of lowered average energy prices as carbon-free resources with VRE have increased. (b) How increased VRE resulted in more volatile energy prices, as VRE output is dependent on weather conditions that can change rapidly.

### *Some Regions Are Evaluating Putting a Price on Carbon*

There is a strong potential synergy between wholesale electricity markets and renewable technology targets. Applying a price to carbon dioxide emissions in wholesale electricity markets would help send efficient price signals to market participants about the value of clean energy resources and align electric systems with decarbonization goals. It may also accelerate the transition to a clean energy future by directly incentivizing new entry of low-carbon resources in locations where they would displace the most carbon dioxide emissions.

In New York, there has been interest in pricing carbon dioxide emissions in addition to the state's current participation in the Regional Greenhouse Gas Initiative (RGGI), a cooperative effort among 10 Northeastern states to cap and reduce power sector carbon dioxide emissions. NYISO, in conjunction with its stakeholders, developed a design where the state sets a social cost of carbon as a price per ton of carbon dioxide emitted based on state goals and the environmental impact. The emitting generators pay for the carbon dioxide they release into the atmosphere. Participants receive economic incentives to invest in low-carbon technologies, and existing participants receive incentives to reduce their carbon emissions. The revenue collected from emitting resources is then returned to wholesale customers. The design also addresses emissions-leakage concerns with neighboring states. *Leakage* refers to a situation in which there are shifts in generation and emissions from resources subject to a carbon price to higher-emitting resources that are not. Leakage can hinder emissions-reduction policies when energy from higher-emitting resources outside of the carbon pricing region displaces efficient, lower-emitting resources within the region. Also, unmitigated leakage can potentially impact investment decisions and consumer costs throughout the system. The way the NYISO design alleviates these concerns is by charging a price at New York's electrical border that does not reflect the carbon price so that a cheaper, higher-emitting supply would not gain market share.

An analysis of the proposal has shown that it would

- ✔ reduce the consumer cost of reaching the state's goal of 100% carbon-free emissions by 2040
- ✔ help grow investment and innovation in clean energy generation
- ✔ promote innovation and efficiency in fossil fuel technology
- ✔ improve public health by encouraging retirement of the highest-emitting generators.

The design has proceeded through the NYISO stakeholder process and now awaits support from New York State. If supported by the state and approved by stakeholders, the NYISO Board of Directors, and FERC, carbon pricing in New York would be implemented (see Figure 4).

PJM Interconnection, which operates in 13 states and the District of Columbia, has a unique challenge related to the diverse range of emission policy initiatives across the region it serves. Three states currently participate in RGGI, while two others have taken steps to join (see Figure 5). Eleven states have renewable portfolio standards or goals employing renewable energy credits, and four states have or are investigating providing subsidies to a broader subset of zero-emitting generation.

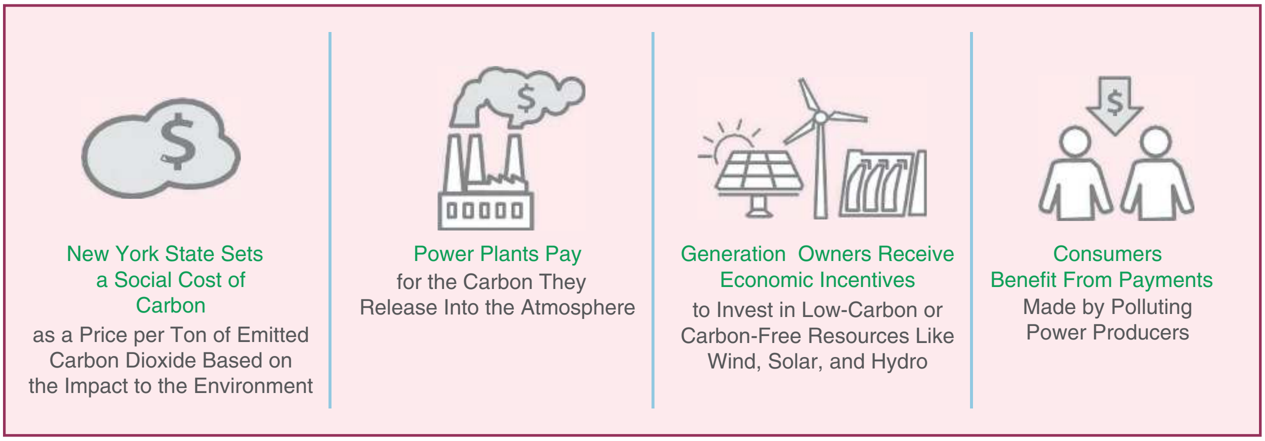



**figure 4.** An overview of NYISO carbon pricing design.

As a result of participation in RGGI, generation in several states is subject to a carbon price. When implementing a carbon price on a subregional basis, the carbon price can have an impact on both emissions levels and energy prices throughout the system through leakage, as described previously. In July 2019, the Carbon Pricing Senior Task Force was formed as part of the PJM stakeholder process to investigate leakage-mitigation approaches. Both one- and two-way border adjustment approaches were explored to mitigate leakage between the states that participate in RGGI and those that do not. A one-way border adjustment approach adjusts the price of transfers into a subregion subject to carbon pricing to account for the carbon price, while a two-way border adjustment approach also adjusts the price of transfers out of a subregion subject to carbon pricing to remove the impact of the carbon price.

### *The Evolving Challenge of Determining Which Reliability Services Are Essential*

Customers measure the reliability of their electric service simply by whether electricity is available when they need it to be. Grid operators fulfill this need using several types of services or products that procure attributes to support the delivery of energy, thus supporting electric reliability. North American markets have several common design features for these reliability services. Nearly all areas are either currently or are planning to co-optimize ancillary services with energy production, use a cascading hierarchy to assign the highest quality services with the highest prices, and use shortage pricing when there is an insufficient supply of services. The names and existence of different services vary across different regions, and the emphasis on different types of services is evolving (see Figure 6).

A few of the services in Figure 6, secondary and tertiary contingency reserve and regulating reserve, are specific products in all the market regions in North America. Others, like flexibility reserve and primary contingency reserve, are products for a subset of regions. Still others, like inertia, do not have specific products in any region. The reasons for the differences include how soon the need for a certain product has arisen, the existing requirements for other products, and stakeholder prioritization processes.

*Resource adequacy* refers to having sufficient capacity installed to meet long-term reliability targets. With a traditional generating fleet, if there is enough installed capacity to serve the peak demand, there should also be sufficient capacity for all other times. However, as the fleet moves toward more VRE and enabling technologies, the task of ensuring resource adequacy changes markedly due to the inherent uncertainty and temporal nature of these technologies.

As more VRE is integrated, the quantity and type of services procured to maintain reliability may change to account for its variability and uncertainty. Regions have implemented or proposed changes to 1) increase the reserve requirement to account for needs beyond contingencies, 2) improve the locational scheduling of reserve so that it can be delivered to where it is needed, 3) address shortage pricing to reflect the importance of different services, and 4) utilize demand curves such that the market places value on procuring more reserve than the minimum requirement. In a growing number of market regions, new products have been introduced (the flexibility/following reserve in Figure 6), highlighting the key difference between the characteristics of services related to addressing variability and uncertainty from those that are needed to address contingencies.

Another key area of evolution in reliability service markets is the mix of resources that participate. In regions with large levels of VRE, operators have shifted to separating products into up (increase supply, reduce demand) and down (decrease supply, increase demand) services, creating opportunities for nonconventional resources to supply the service while still ensuring reliability. To benefit the reliable operation of the system, reserve services must also be deliverable and not awarded to resources unable to respond due to transmission congestion. Much of North America has been making significant changes to allow for the participation of electric storage, demand response resources, and even resources located on the distribution system within all the

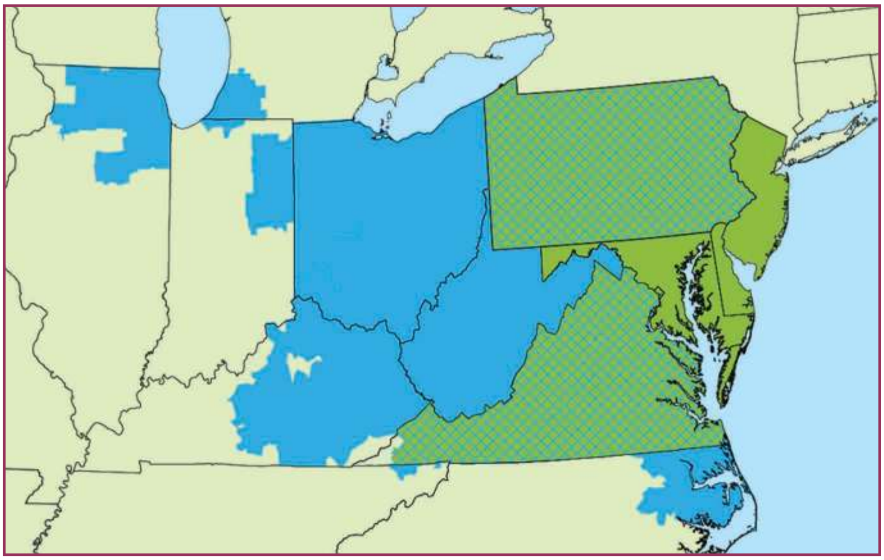


**figure 5.** PJM Interconnection's footprint (shaded in green, checkered green, and blue) with the states that currently participate in RGGI in green, the states that have taken steps to join in checkered green, and the regions that do not participate in blue.

different reliability services in a cost-effective and high-performing manner.

Characteristics such as the ability to maintain nominal voltages, respond to frequency excursions, and ensure stability are all necessary for grid reliability. Historically, generators have inherently provided these services, but as more inverter-based resources are integrated, these attributes are becoming more important. Different technologies may provide the attributes in different ways, making it essential when designing markets to incentivize the attribute provided to the grid and not how the specific technology provides it today. As an example, sufficient synchronous inertia is required to maintain stability, and inertia markets are under discussion as a future possibility. Although not the exact same thing, future systems with extremely fast controls coming from inverter-based resources can replicate some of the support that inertia provides. Research has even been conducted on ways that grid-forming inverter technology can work without any synchronous inertia. As the resource mix continues to evolve, it will be important to understand the types and amounts of these attributes and the corresponding products necessary to support the reliable operation of the grid, regardless of technology.

## What Will the Future Market or Regulatory Structure Look Like?

Market structures differ not only across the globe but also within North America. For example, of the nine organized electricity markets, four have centralized capacity markets (one voluntary), one is transitioning to a centralized capacity market, two have bilateral resource adequacy requirements, and two others have no resource adequacy requirement. It is impossible to predict what the future structure will look like, and it is possible that different regions will differ in regulatory practices, carbon/renewable goals, and stakeholder and consumer opinions, among other features. That said, researchers and practitioners have started looking at a few structures and market designs that can meet some of the principles discussed previously.

There are generally three schools of thought regarding the future electricity market structure. First, existing market designs will function just as well as they do today, or with minor incremental changes. Second, substantial changes are required for markets to function properly, given the future resource mix. Third, markets should be eliminated or minimized in favor of a return to central planning, vertical integration, and cost-of-service pricing. There are several variations of the actual market design across each option, and readers are encouraged to review the reports referenced in the "For Further Reading" section. Some of the options that have been proposed in previous studies are briefly discussed, some by the authors, without claiming any one option is superior to another.

The market design philosophy that underpins North American wholesale energy markets—marginal cost pricing using bid-based, security-constrained economic dispatch

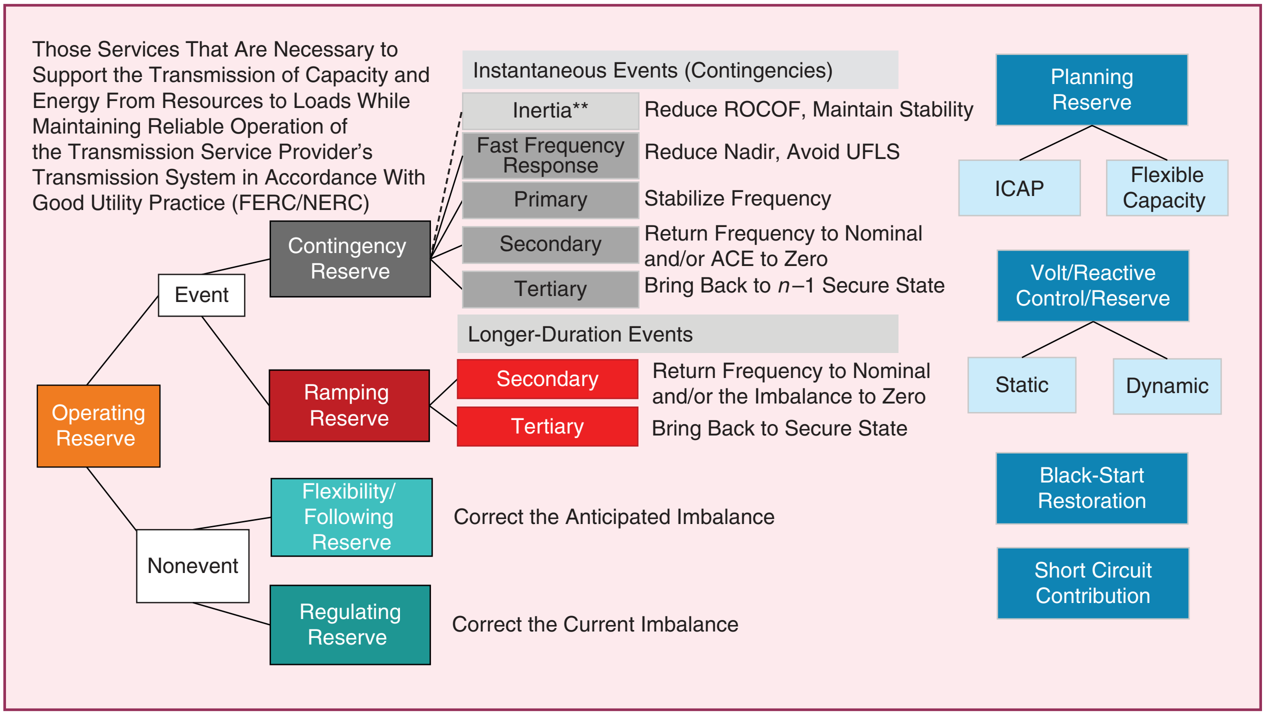



**figure 6.** An example set and categorization of reliability services. NERC: North American Electric Reliability Corporation; ROCOF: rate of change of frequency; ULFS: under-frequency load shielding; ICAP: installed capacity. (Source: Electric Power Research Institute; used with permission.)

with locational pricing—was conceived to deliver reliability efficiently, regardless of the mix of resources or their short-run production cost profile. That market design, well applied in practice, may be relied upon to perform those tasks in a low-carbon power system. Proposers of this option suggest that this structure, with economic dispatch as its bedrock, along with active decentralized forward procurements between buyers and sellers, could lead to an adequate supply mix with short-term signals to ensure that the system maintains reliability. Some proposers suggest additional measures (e.g., setting minimum financial standards for retail service providers) to support needed liquidity in bilateral trade in long-term options, through which generators and load-serving entities can mitigate their risks in the spot market, while others do not think that is necessary. Otherwise, the proposers suggest that energy market pricing focused on operational needs, combined with endogenizing the value of carbon dioxide emissions, could provide sufficient revenue to meet operational reliability and investment needs. This type of structure can also improve the participation of responsive demand that could respond by consuming less when there is insufficient VRE or provide opportunities for storage that might sell energy at the opportunity cost of being unable to sell later during a critical, high-price period.

A second option discussed is to pair the existing energy market with some type of organized forward market. The key difference in these proposals, compared to the previous ones, is the notion that energy markets alone may not sustain efficient investment. This is due to the possibility that short-term energy prices may have greater volatility and may not average to long-term marginal costs as well as the uncertain prospects of capital recovery of infrequently used assets. The proposers suggest that the energy market alone could get investment right, but that we must also consider the risks that this may not happen. This may be particularly challenging for the set of enabling resources providing flexibility and additional reliability services during low VRE production. The quantity of the enabling resources must be large enough to buy energy when VRE

**table 2. Corneli et al. provide a common set of considerations for long-term market design, but each has their own proposals, with the key differences shown.**

| Key Features | Configuration Market (Corneli) | Long-Term Energy Market (Pierpont) | Firm Market (Gimon) |
|---|---|---|---|
| • How is a long-term market portfolio selected? | Bid-based, region-wide system co-optimization model | Through exogenous guidance from policy makers and system planners | Bid-based, region-wide system co-optimization model |
| • What is the objective function of the long-term market? | Minimize the expected cost of meeting reliability requirements across a wide variety of possible weather-, load-, and resource-availability scenarios | Minimize the cost of meeting a share of total load, specified by policy makers, from the eligible resources that choose to bid | Minimize the cost of producing a significant share of total energy through a "default dispatch," which short-term markets take as a baseline for real-time operation |
| • What products are bought in the long-term market? | Capabilities to perform as needed to meet objective functions | Annual energy output, subject to shape; location; resource type; and guidance from policy makers | Long-term energy schedules |
| • How is fixed cost recovery carried out for selected resources? | Resources selected are eligible for fixed-cost recovery through a variety of means, including power purchase agreements, tolls, regulated tariffs, and clearing prices as worked out through additional design work | Long-term power purchase agreements for energy, which may be either pay-as-bid or uniform market clearing price | Pay-as-bid long-term power purchase agreements |
| • Is participation mandatory? | No | No | Participation is presumed but not required |
| • How often is the long-term market conducted, and how much does it purchase? | Periodically, e.g., once every three to five years | Annually | Periodically to cover incremental amounts of needed resources |
| • Does the long-term market drive rapid decarbonization and how? | Where co-optimized clean energy resources are cheapest, the market will naturally select decarbonizing choices but will otherwise reflect carbon prices and efficient policies | Presumably, both through clean energy resources becoming increasingly competitive and through policies | Where co-optimized clean energy resources are the cheapest, the market will naturally select decarbonizing choices but will otherwise reflect carbon prices and efficient policies |

production is excessive (to raise prices) but small enough not to consistently exceed energy needs during scarcity conditions. Stochastic simulation tools could be used to determine the optimal set of resources with the needed attributes while being able to support investment where short-term prices may be too uncertain to make those decisions. Although these options are reminiscent of existing forward-capacity markets and transmission planning processes, proposers suggest voluntary participation and a focus on the incentivizing attributes needed in the future resource mix while primarily relying on short-term energy markets. Three possible options for long-term forward markets are shown in Table 2.

Other options are possible. A recent set of awards was provided through the U.S. Department of Energy's Advanced Research Program, which were aimed at evolving system operations and electricity market operations to a more risk-driven paradigm. The projects will propose and develop new operating and market designs that evaluate and structure performance into market incentives, establish transparent risk-assessment methods, leverage existing approaches to quantify and mitigate risk, and identify how resource performance assessment can create new business opportunities to mitigate risk. It is expected that the market and market clearing algorithms will capture uncertainty, allocate the cost of uncertainty to those who cause it, and reward those who mitigate it.

Another option is moving back toward a more 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 inevitable, a regulated system may be a feasible option. That does not make things 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, should use the same engineering and economic principles for this future resource fleet, with poor decisions still resulting in inefficient or unreliable outcomes.

## Conclusions

Electricity markets have always been complex due to their unique physics of electricity supply and delivery. That will continue regardless of the future grid. There is no crystal ball foretelling how best to achieve a system that emits no carbon and how to get there cost-effectively. During this transition, innovations may cause paradigm shifts that require rethinking. Although regions across North America are seeing substantial levels of VRE, conversations about what market structure and design may be most appropriate for each region are just beginning. Further work is needed to evaluate the different options and how they may work across different jurisdictions. To supply the energy and services for this future system, engineering and economic principles are needed to provide the foundation for evaluating which options are best to support a system that is reliable, economically efficient, and allows the needed resources an opportunity to recover their costs and be rewarded for effective innovation.

## For Further Reading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