Evolution of Power Market Structures and Remuneration

To support the energy transition and incentivize performance and investment

Building a world that works

Executive Summary

The electric power system, and indeed the energy industry, is in the midst of a transition towards net zero carbon technologies as part of the effort to fight climate change and meet the objectives of the Paris Agreement. Since the 1990s, electric power technology innovation has sped up to help address the climate change problem, bringing utility scale wind and solar to capital cost parity in many locations with conventional, fossil fuel resources. Additionally, high efficiency gas turbines combined with increased natural gas supplies in North America and elsewhere have enabled further fuel switching from coal.

GE has a systems perspective on the energy transition with a suite of complementary technologies and services for the energy value chain, including gas-fired power with hydrogen and carbon capture utilization or sequestration (CCUS) capability, onshore and offshore wind, hydro, small modular reactors, battery storage, hybrid systems and grid solutions needed for the energy transformation. More importantly, we believe it is our responsibility to support this transition through our long-standing relationships with customers, energy industry stakeholders, and policy makers - collaborating to build an energy system that works for everyone.

New electricity market products and remuneration schemes that incentivize the attributes needed now and in the future are required as energy systems and electric power grids transition to net zero carbon technologies. Competitive power markets should pay for energy, dependable capacity, and essential reliability support services in a technology agnostic way. Power market design is an important tool that can't be considered in isolation. Clean and alternative fuel incentives and feed in tariffs, renewables energy standards, carbon pricing mechanisms, and cross sector coupling for electrification, can all work together to establish power markets and resource investment signals for the energy transition towards net zero carbon energy systems.

This paper discusses the following key building blocks for successful competitive power markets to effectively help incentivize the needed characteristics of the changing mix of electric power technology, adequately pay for this investment, and help ensure a reliable, stable and resilient power grid.

- Maintain wholesale energy markets based on locational marginal costs, either zonal or extended to nodal, to be paid to participating resources at the marginal market price, the last accepted offer.
- Implement forward capacity markets or capacity remuneration schemes to pay for demonstrated, dependable capacity for required durations to provide signals for resource adequacy and sufficient long-term resource investments.
- Add essential reliability support services that go beyond conventional ancillary services to pay for additional required resource features and capabilities required for secure system operations and grid stability. These include services such as fast frequency response, dispatch and operational flexibility, fast ramping resources, inertia, and voltage support.
- Invest in demand-side infrastructure, digitization, and smart grid to further enable demand-side participation in power markets to enable the bi-directional grid.

Energy Transition and Need for Change

The electric power system, and indeed the energy industry, is in the midst of a transition towards net zero carbon technologies as part of the imperative to fight climate change and meet the objectives of the Paris Agreement, and to accelerate actions and investments that limit global warming to less than 2 degrees (and preferably no more than 1.5 degrees) Celsius[1]. The Paris Agreement, in force 4 November 2016, requires all signatories to reduce greenhouse gas emissions largely responsible for global warming, driving more urgent action than the previous Kyoto Protocol[2].

Since the 1990s, innovation of electric power technology has accelerated in response to the climate change problem, bringing the levelized cost of energy (LCOE) of utility scale wind and solar to parity with conventional, fossil fuel resources in many regions of the world. Additionally, high efficiency gas turbines combined with increased natural gas supplies in North America and elsewhere have enabled further fuel switching from coal, resulting in substantial reductions of CO_2 emissions from electricity generation.

The transition of the electric power system necessitates a significant change to the traditional power system and its operation. The electric grid is moving from primarily central station power plants towards a more distributed resource network. As a result, locational marginal energy costs that were historically largely driven by the cost of fuel for coal, gas and oil, are moving towards the zero fuel priced technologies of wind and solar, also known as variable renewable energy (VREs) resources. The alternating current (AC) system based on rotating equipment and associated ancillary services, is migrating towards a system with less rotating equipment and more power electronics, also known as inverter-based resources (IBRs). In regions with high penetration of VREs, new challenges are emerging that require not only new operational procedures but new ways of incentivizing the contributions of generation, storage, transmission, distribution and consumer equipment and services that the future grid requires to remain stable, reliable and resilient.

As the energy systems transforms, and technologies shift to support the path towards net zero carbon, power market mechanisms and remuneration schemes must likewise evolve to incentivize the necessary characteristics of this changing mix of electric power technology, while adequately paying for required investment and ensuring a reliable, stable and resilient power grid.

> To support the path towards net zero carbon, power market mechanisms and remuneration schemes must evolve to incentivize the changing technology mix.

Drivers of Change

Traditionally, electric power systems were planned and built to include central station, conventional generation to serve mainly passive and predictable consumer demand via unidirectional transmission to distribution to consumers. Most electric power grids today are largely made up of conventional generation comprised largely of coal, gas, hydro and nuclear synchronous machines, that are highly dispatchable, rotating equipment capable of maintaining the frequency of the AC grid. System level integrated resource planning has been the normal mode of operation, optimizing future plant buildout to minimize systems costs, including emissions and other externalities, and to meet reliability metrics such as reserve margin or loss of load expectation.

As electric power systems transition to net zero carbon emissions, many changes are taking place. These include the increased penetration of VREs such as wind and solar that are power electronics interfaced generation with inverter-based technology. These IBRs have capital costs with zero fuel costs and low fixed and variable operating costs. Since wind and solar plants are dependent on when the wind blows and sun shines, they are generally not dispatchable and typically treated as load-modifiers, especially given the zero-cost fuel. Wind and solar plants are also location dependent on the wind and solar resource, often away from load centers and widely distributed. System planning must now consider additional variables and uncertainties, including greater weather dependencies, locational aspects of system resources and net load shapes that reflect the power system demand after wind and solar generation. The traditional reliability metric of reserve margin on peak demand hours is now insufficient, as the energy shortfall for the system is also a function of the wind and solar availability that reflects daily and seasonal cycles. To interconnect more wind and solar resources that often are located relatively far from load centers, transmission and distribution grids must be expanded and strengthened. In the recent USA Net-Zero America study[3] conducted by Princeton, an aggressive electrification and high renewables penetration scenario adds more than 1.7 million GW-km of transmission by 2050. The European Network of Transmission System Operators for Electricity (ENTSO-E) published its ten-year network development plan (TYNDP)[4] in 2020 that detailed 154 transmission projects totalling 43,000 km with 93 GW of cross-border interconnector capacity out to 2040.

In addition to the distributed aspects of wind and solar resources, more consumers are becoming prosumers, both consuming power from the grid and producing power to send

back into the grid with distributed energy resources (DERs[5]), rooftop solar for instance. The advent of the prosumer coupled with active demand-side management and emerging electric vehicle-to-grid capabilities requires a bi-directional grid.

These power system changes brought on by the energy transition likewise require evolution of power markets structures.

Electricity Market Challenges

While policy can be used to fund technology advancement and demonstration in the energy transition, power market structures should provide that remuneration mechanisms incentivize operational efficiencies and long-term investments. Therefore, power market design is critical to enable the desired energy transition and can't be considered in isolation. Enablers such as clean and alternative fuel incentives, feed in tariffs, renewables energy standards, carbon pricing mechanisms, and cross sector coupling for electrification, etc., can all work together to establish required power markets, resource investment signals and physical and financial hedging tools.

Competitive power markets must incentivize new and innovative technologies creating a path to net zero while maintaining dependable resource (including storage) capacity and ensuring availability of essential system support services required for reliable and stable operation of the electric grid. These technologies include wind, solar and energy storage, carbon capture utilization or sequestration (CCUS) technology, increased hydrogen fuel options, CO_2 and hydrogen trading and storage hubs and pipeline networks, and grid forming inverter technology, to name a few.

Transmission and distribution (T&D) investments are still largely regulated under cost-of-service type recovery mechanisms for consumers in assigned/licensed service territories. As T&D requirements for the future grid increase and potentially their utilization drops, new cost allocation mechanisms are being considered and implemented. Socialization of transmission costs to interconnect renewable generation has been effective. For example, to quickly expand the transmission system within Texas to deliver wind generation from the west, the Public Utilities Commission of Texas (PUCT) established Competitive Renewable Energy Zones (CREZ) that are areas of high wind resource. Working with the Electric Reliability Council of Texas (ERCOT) and stakeholders, the CREZ program interconnected over 3,500 miles of transmission line and 18.5 GW of wind within 8 years of inception, with the costs and benefits socialized across ERCOT market participants, and ultimately consumers. Other models allocate the associated costs of transmission and grid improvements to the resource incurring the costs which are then collected by the resource owner in the wholesale power market mechanisms.

Visibility and controllability of DERs to distribution system operators and expanded market products to incentivize and remunerate DER contributions require investment in demand-side infrastructure, digitization, and smart grid. The participation of DERs and demand-side resources in the wholesale power markets is further enabled by FERC Order 2222[6] in the USA. Wholesale power market participation and bi-lateral transactive energy requires secure transaction platforms, such as blockchain, along with increased digital solutions, smart grid such as advanced distribution management systems (ADMS), smart appliances, active demand-side management and emerging vehicle-to-grid capabilities. Distribution level resources that manage electricity use such as load control switches or produce their

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electricity at or near the point where it is used such as rooftop solar, can provide significant benefits to the electric grid with capacity, energy and essential reliability support services.

We live in a multi-speed world and every country and region is at a different stage in the energy transition on their decarbonization journey. The focus of this paper is on competitive power markets that are trending towards high penetration of variable renewable energy (VREs) resources. The pace at which new electricity market design is needed will therefore vary by country and region, consistent with their stage of progress in the energy transition.

Existing Power Market

Power systems operate under a variety of structures, depending upon the country, state and region where they are located, as well as the degree of deregulation that has taken place. Prior to the 1990s, vertically integrated utilities were the predominant business model. They provided generation, transmission and distribution services that served customers in franchised/licensed areas under cost-of-service models with a regulated rate of return. In the 1990s, various pathways of "deregulation" or more specifically decoupling of ownership of generation resources from transmission and distribution occurred. This was first implemented via open access to transmission by independent power producers (IPPs) to create competition in the otherwise monopolistic power system. To further facilitate competition, drive system efficiencies and encourage innovation in the electric power and fuels sectors, competitive market structures evolved in systems around the globe with some jurisdictions taking competition for power supply down to the household level.

Organized, competitive wholesale electricity markets are now prominent in countries and regions around the world - North and South America, Europe, Japan, Australia, and India to name a few. These markets are generally overseen by independent system operators (ISO) or regional transmission organizations (RTO) who facilitate the electric marketplace within their jurisdiction and provide bulk electric system planning and oversight. Market participants include utility generation owners, independent power producers (IPPs), transmission system owners (TSOs), distribution system owners/operators (DSOs) and distributed energy resources (DERs). Supply-side resources and, increasingly more often, demand-side resources, can transact through a wholesale market or via bi-lateral purchase power agreements (known as fixed PPAs) or variable PPAs, often referred to as contracts for differences (CfDs) to provide power to distribution utilities, load serving entities (LSEs), load aggregators and in some cases directly to consumers.

Most organized, competitive electricity markets have three primary sources of revenue to electric power generators: the energy market, the ancillary services market, and the capacity market. Traditionally, the energy market that reflects the variable operating costs of a plant (fuels costs, variable maintenance costs and emission costs) has comprised the largest of the three sources in terms of total market value and revenue component.

The energy market price mechanisms are auction models that typically reflect the marginal cost of energy supply in $/MWh.[7] Generators and power suppliers bid to supply energy into a competitive power market typically based on their marginal costs of producing energy, with limited capital or fixed costs included in energy market bids. In locational marginal wholesale energy markets, either zonal or extended to nodal,

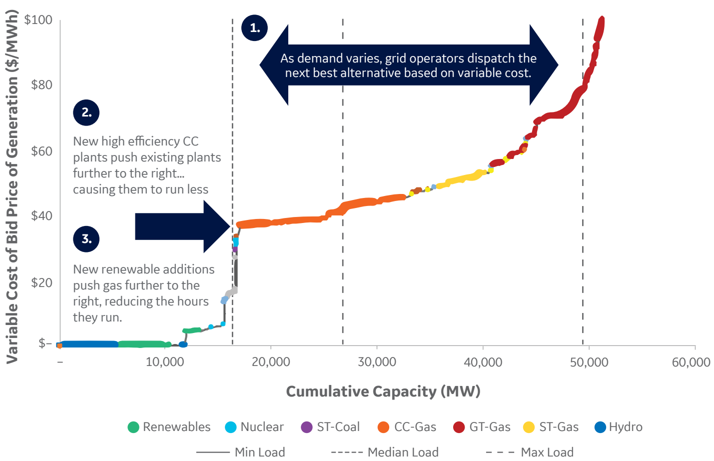

Figure 1: Dispatch stack example.[16]

providers of electricity are usually paid on the marginal market price or last accepted offer to meet the demand during a given period of time, called the marginal clearing price, in the auction mechanism. This means all providers are paid the highest price to clear the incremental MW of demand. Nodal pricing mechanisms provide more granular locational signals that can inform operational efficiencies such as congestion avoidance. Energy prices in the balancing or day-ahead markets based on the marginal costs of resources can accurately reflect the value of the resource location, period of energy generation (or charging) and externalities such as carbon pricing. These mechanisms also provide for market liquidity, price transparency, support creation of hedging instruments and are the foundation of purchase power agreements (PPAs) and contracts for differences (CfDs). In fact, most competitive markets have some noticeable level of power traded (25%-40%+ of total demand) via instruments such as PPAs and CfDs.

The second market design component, and historically the smallest in terms of total market value size and revenue component available to suppliers, is the ancillary services markets. Electric grid operators need resources to provide certain functions or services to maintain grid stability and reliability. The ancillary services market can be divided into two types of service offerings: regulation and reserves. Regulation helps grid operators to match up the electricity that is being consumed (load) and the electricity that is being produced (generation), and thus keep the grid functioning normally. Reserves help to recover system balance by making up for generation deficiencies if there is a loss of a large generator or a partial grid outage.[8] Reserve services include synchronized reserves that are provided by resources operating and synchronized to the system, and non-synchronized reserves that require start-up of a resource then synchronization to the grid. Ancillary service functions ensure that the grid is operated in a safe and reliable manner. Suppliers are typically reimbursed for providing these services through ancillary service prices and payments. The importance of ancillary services markets is growing as power grids evolve with more VREs and demand sources.

Lastly, as the energy market and ancillary services markets are intended to predominately cover suppliers' marginal costs and reflect scarcity pricing in the case of energy only markets, some markets also include a capacity price mechanism.[9] While not present in every market structure, the capacity market is typically an auction based mechanism designed to cover suppliers' fixed costs, that include fixed operation and maintenance costs, and sufficient income to cover a generator's debt service and return on equity. Capacity markets are designed to procure adequate generation supply (or demand reduction) to help ensure system reliability to cover the peak demand with some level of capacity reserve. This means that certain power suppliers as well as consumers or aggregators of demand, supply and storage sources may earn revenues from their respective capacity markets by simply being able to provide power (or reduce demand) in case it is needed. For example, a combustion turbine may be dispatched for 1% of time in any given year, but if they are able to do so reliably and have cleared the auction market, they earn capacity payments for the auction period.

New remuneration mechanisms are needed for resource investment recovery and maintaining system resiliency and reliability as power systems transition to more net zero carbon

technologies. Transmission and distribution grids will expand and flex to accommodate higher penetrations of VREs, and consumers will continue to take a more active role in their energy decisions. While the revenue potential from the wholesale energy market is anticipated to decline with increasing penetration of zero-cost fuel VREs, more revenues will need to come from the capacity and ancillary services markets to sustain existing generators and drive new investment thus enabling reliable operation and development of power systems.

Evolution of Power Market and Remuneration Structures

Power market mechanisms and remuneration schemes must evolve to incentivize system operations and technology investments for the future mix of technologies to support a reliable, stable and resilient power grid. Since Ireland is well down the path towards a net-zero carbon power system, it provides a good example of how the pricing components of power markets could evolve. Ireland currently generates about 43% of total electricity and up to 75%[10] of the instantaneous generation from VREs, primarily wind. As Ireland targets 80% of electricity generation from VREs by 2030, EirGrid, the all-island transmission grid operator, is envisioning the evolution of the future power market structure as shown in Figure 2 to adequately incentivize technology investment and provide required support services for reliable and stable operations. This figure illustrates that the revenue pool for variable cost components of energy is expected to decrease, largely driven by less energy from conventional fossil-based power plants, and that the share of capital costs and support services will increase to adequately compensate for resource adequacy and operational efficiency.

Energy Price Mechanisms

As the penetration of renewables increases, and wind and solar become a more prominent portion of the generating mix, the marginal energy prices will include more zero and negative locational prices. This is already being seen in some markets, including the Electricity Reliability Council of Texas (ERCOT, Texas, USA) and Australia Electricity Market Operator (AEMO), New South Wales in Australia and the Single Electricity Operator (SEMO) in Ireland. Negative energy pricing, which occurs more frequently with high penetrations of wind and solar, is a signal of surplus generation which cannot be economically absorbed in the system, for example during periods of high wind or solar output and low demand. Electrification of thermal demand, addition of storage technologies (including electric vehicles) and addition of hydrogen electrolysis can all help utilize excess wind and solar energy.

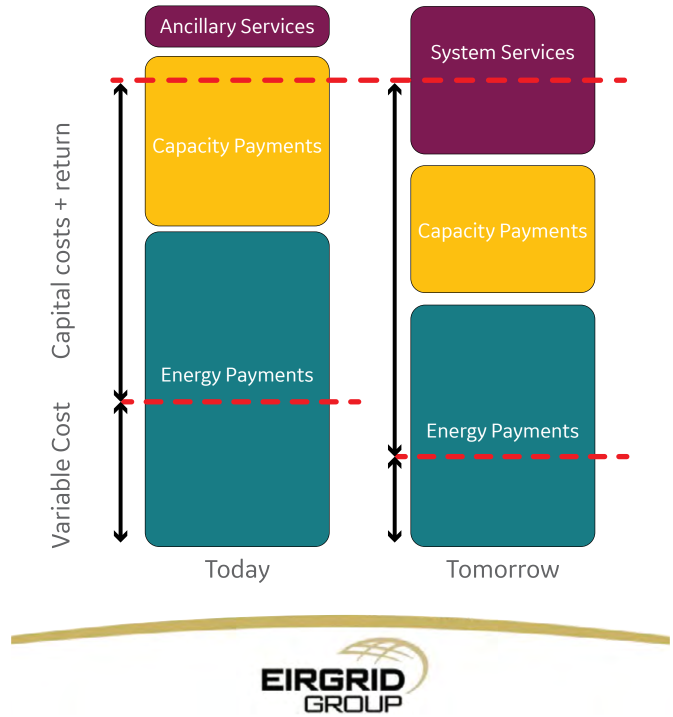

Figure 2: EirGrid view on market design, 2018.

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Marginal energy prices that are nodal or locational will give the most accurate price signals as to where increase demand or add price responsive load to take advantage of high penetrations of wind and solar. Similarly, nodal or locational prices can indicate areas of congestion that may be alleviated with the addition of transmission, distribution or energy storage assets.

One approach to address more zero and negative marginal energy prices that is being discussed by the Federal Energy Regulatory Commission (FERC) in the USA is to utilize and improve upon the “scarcity pricing” feature, such as in ERCOT and known as the Operating Reserve Demand Curve (ORDC). This mechanism causes energy prices to rise during scarcity events. Similar to AEMO and many European zonal energy markets, ERCOT does not utilize a capacity market and has high renewable penetration. The functionality of this pricing mechanism in an energy only market helps to send the correct pricing signals to energy suppliers during energy scarcity periods. A scarcity pricing mechanism would almost by definition address a period of tens to hundreds of hours in the year making it difficult to plan for and count on as revenue for an energy supplier. The lack of revenue certainty for plant investment decisions is a primary challenge for scarcity pricing in an energy only market and therefore not the best option to encourage longer-term resource adequacy.

A related consideration is how to reflect the increases in energy delivered from zero marginal cost resources such as wind and solar into retail rates especially as near-term marginal prices will largely reflect conventional generation. Consumers should benefit from lower priced energy from wind and solar resources. A windfall charge or tax is one pricing mechanism that can be applied to address extremes in energy prices, especially due to scarcity pricing the reflected in fossil fuels and translated to marginal energy prices.

Capacity Price Mechanisms

Capacity markets or remuneration schemes can pay for demonstrated, dependable capacity to ensure signals for resource adequacy and sufficient long-term resource investments. Capacity types vary significantly in their characteristics. Different resources provide firm, dependable capacity over various time durations, at different levels of certainty and availability, while delivering different reliability support features such as fast ramp rate. Power generation, T&D dynamic scheduling equipment and demand-side participants must be required to demonstrate capability and availability when called to support the system in order to be paid. A forward capacity market or auction for multiple years can provide the signals required for long-term investments in dependable capacity required for system reliability.

As the penetration of VREs increases, effective load carrying capacity (ELCC) is increasingly being used to assess the dependable capacity. For example, the PJM Interconnection[11], and the California Public Utilities Commission (CPUC)[12] have adopted ELCC into their dependable capacity calculations. With higher renewable penetration, the times of high potential loss of load expectation (LOLE) are moving to traditionally

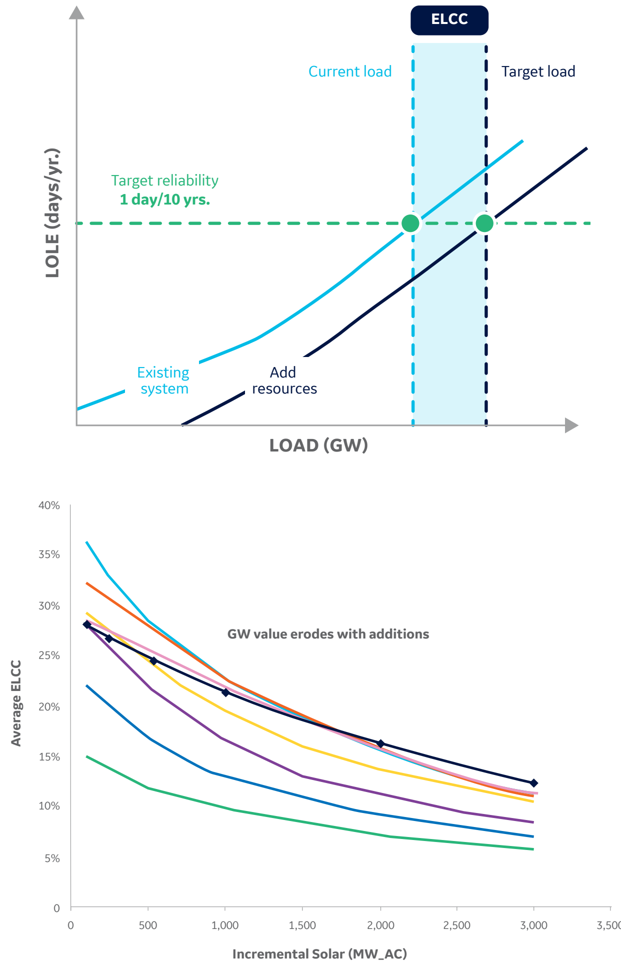

Figure 3: ELCC approach and example application to IBRs capacity credit.[17]

non-peak hours (middle of night, spring, fall) and for varying durations. These periods require not only dependable capacity but energy and the support services to maintain system reliability and stability. The ELCC methodology calculates the ability of a resource to provide reliable energy during times of high potential loss of load. This has the result of declining ELCC for wind, solar and batteries as more are added to a system since those technologies can’t be effectively “dispatched” during those times. ELCC could be used when determining the amount of dependable capacity to be procured and compensated in a capacity market.

Capacity markets have traditionally provided some of the “missing money” portion of revenues for generators by paying them a price intended to cover the capital and fixed costs of a new entrant that could provide needed capacity to the power system. Recently, capacity market design is causing discussion regarding two emerging issues: zero-bid capacity offers and subsidized costs due to aggressive decarbonization mandates.

At lower levels of renewables penetration, wind and solar inherently earn towards their fixed operating costs on inframarginal rents in the energy market due to their zero or near-zero variable operating costs in an energy market set by fossil fuel generation. This allows renewable energy suppliers to bid into the capacity market with low to zero bid offers, meaning they serve as "price takers," receiving a capacity payment at the market clearing price. As renewables serve a larger percentage of the energy mix, their bid-offer prices could suppress clearing prices for the broader capacity market, providing less revenue to conventional thermal resources, challenging their economic viability.

Aggressive decarbonization policy at the country or state level, has created support for the rapid development of local renewable energy suppliers through renewable tax incentives, credits, carbon pricing and other financial mechanisms. These country or state provided benefits provide renewable energy suppliers an additional revenue stream that contributes towards their capital costs. The same type of mechanisms can be deployed for carbon reducing technology such as CCUS, direct air capture (DAC) and hydrogen electrolysers. These pricing schemes are appropriate and necessary to pay for desired technology and environmental outcomes.

Support Services Price Mechanisms

Essential reliability support services go beyond conventional ancillary services to facilitate deployment of additional required resource features and capabilities to support system operations and grid stability. As the penetration of VREs or IBRs increases, the net load (demand minus solar and wind generation) to be served will have new net peak demands and energy requirements at varying times and durations than previously seen. Peak demand in grids with high penetration of solar is likely to occur later in the evening after solar generation peaks or prior to sunrise, in previously regarded as off-peak periods, or in shoulder months of the spring and fall, see Figure 4.

The abovementioned periods require not only dependable capacity but energy and the support services to maintain system reliability and stability. For example, the decline in system inertia traditionally provided by rotating machines requires inertia from other sources. IBRs do not supply intrinsic inertia, but they can be programmed to supply fast

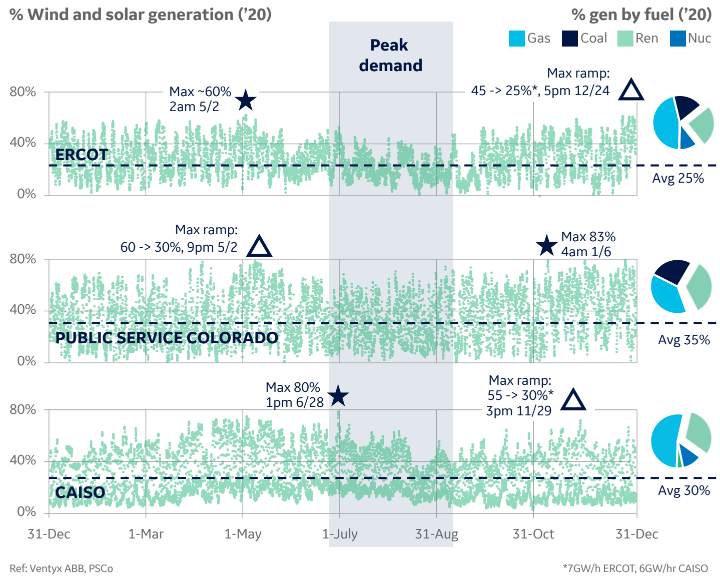

Figure 4: Wind and Solar penetration in 2020.[18]

frequency response (FFR) services that have a positive impact on system response. New technologies like grid forming controls will allow IBRs to provide inertia in a way very close to how conventional generators provide inertia. To arrest a high rate of change of frequency (RoCoF) after a contingency event in a system with low inertia, resources that can provide FFR action that is illustrated in Figure 5 below, should be compensated for this essential reliability support service.

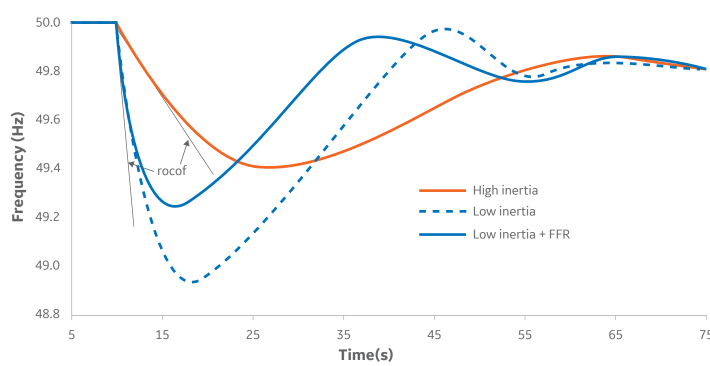

Figure 5: Frequency regulation with Fast Frequency Response (FFR).

Similarly, support services such as dispatch or operational flexibility, fast ramping resources and voltage support have been traditionally provided by rotating equipment. These should be specifically required and compensated as penetration of IBRs increase to help ensure adequate reliability of the system. System and market operators should define clear rules for the delivery

Competitive power markets should pay for energy, dependable capacity, and essential reliability support services in a technology agnostic way

of these services and enable market participation mechanisms for technologies that can provide them. A good example is the Ireland System Operator (EirGrid), who has launched a program called DS3 that defines different types of grid support services. Technologies are certified to provide the services as they demonstrate they can meet the posted requirements, therefore IBRs can participate in these new markets as the technology allows and develops. Another example is that ERCOT is currently developing a Contingency Reserve Service (CRS) ancillary service product designed to serve as an additional operational reliability tool to help maintain grid reliability by managing the increasing variability and ramping issues associated with higher renewable generation penetration on the grid in the future.[13]

In the USA, FERC 2222 allows Distributed Energy Resources (DERs) to participate in competitive marketplaces. The Order could be a game changer for the Regulation Market, as it gains a valuable new participant. DERs can be paired together with electric storage devices like batteries and flywheels to function as hybrid units and/or microgrids, which can interconnect to the larger power system or operate as power "islands," closing the connection to the "macrogrid" and serving only local load, thus maintaining service to critical loads in times of emergency. As an example, PJM is currently working with industry leaders as microgrid technologies evolve, to explore ways to integrate distributed energy resources efficiently and economically into the PJM markets and operations.[14]

Recommendations for Power Market Mechanisms

New electricity market products and remuneration schemes are required as energy systems and electric power grids transition to net zero carbon technologies. Competitive power markets should pay for energy, dependable capacity, and essential reliability support services in a technology agnostic way.

As listed below, we propose key building blocks for successful competitive power markets to help incentivize the provision of needed characteristics in the future mix of electric power technologies, adequately compensate to signal for this investment and that will help ensure a reliable, stable and resilient power grid. Power market design is an important tool that can't be considered in isolation. Clean and alternative fuel incentives, feed in tariffs, renewables energy standards, carbon pricing mechanisms, and cross sector coupling for electrification, can all work together to establish power markets and resource investment signals. These mechanisms also provide for market liquidity, price transparency, support creation of hedging instruments and are the foundation of competitive PPAs, CfDs and similar contractual agreements.

- Maintain wholesale energy markets based on locational marginal costs, either zonal or extended to nodal, to compensate participating resources at marginal energy price, i.e., at the last accepted offer.
- Implement forward capacity markets or capacity remuneration schemes to pay for demonstrated, dependable capacity for required durations to provide signals for resource adequacy and sufficient long-term resource investments.
- Add essential reliability support services that go beyond conventional ancillary services that are remunerated for additional required resource features and capabilities to support system operations and grid stability. These include services such as fast frequency response, dispatch and operational flexibility, fast ramping resources, inertia, and voltage support.
- Invest in demand-side infrastructure, digitization, and smart grid to further enable demand-side participation in power markets to enable the bi-directional grid.

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4 ENTSO-E, Ten-Year Network Development Plan (TYNDP) 2020, Main Report and Highlights, January 2021, version for ACER opinion, https://tyndp.entsoe.eu/.

5 DERs are distribution-level generating resources that produce their electricity at or near the point where it is used, such as distribution-scale wind turbines, photovoltaic arrays, fuel cells, and even reciprocating engines and backup generators.

6 FERC Order 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Issued September 17, 2020 https://www.ferc.gov/news-events/news/ferc-opens-wholesale-markets-distributed-resources-landmark-action-breaks-down.

7 Marginal Cost can be defined as the cost to produce one additional unit of what is needed. In power market terms, it would be producing one additional MWh in the energy market or providing one additional MW of supply in the capacity market.

8 https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx

9 In the United States, these markets include ISO-New England (ISO-NE), New York ISO (NYISO), PJM, and Midcontinent ISO (MISO)

10 EirGrid announced on April 7, 2022 that “Electricity Grid to Run on 75% Variable Renewable Generation”, https://www.eirgridgroup.com/newsroom/electricity-grid-to-run-o/index.xml

11 https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability. PJM is an RTO that operates the bulk electric system for large portions of 13 mid-Atlantic USA states and Washington D.C.

12 2020 Resource Adequacy Report, December 2021, California Public Utilities Commission Energy Division, https://www.cpuc.ca.gov/RA/

13 Delivering a Secure, Sustainable Electricity System (DS3), EirGrid’s multi-year program to increase energy consumption from renewable energy resources.

14 Public Utility Commission of Texas Filing #52373 Item # 268: “Review of Wholesale Electric Market Design” https://interchange.puc.texas.gov/Documents/52373_268_1172004.PDF#:~:text=ERCOT%20Contingency%20Reserve%20Service%20%28ECRS%29%20%28New%20Ramping%20Ancillary,generation%20penetration%20on%20the%20grid%20in%20the%20future.

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