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energy system debate

what lies ahead for the future?

THE DEBATE ABOUT CENTRALized versus distributed energy generation has been polarizing opinions among experts and stakeholders for many years. Promoters of distributed energy resources (DERs) present the transition to strongly distributed energy systems as unavoidable and disruptive, driven by strong enablers such as technology innovation, big data, information technologies, and digitalization. Future grids are imagined as integrated local hubs for energy services that connect electric mobility, advanced thermal energy services, and a whole universe of smart connected devices, usually powered by distributed renewable electricity, notably solar photovoltaics (PVs). In this vision, digitalization and big data enable new services and empower consumers.

Opponents of DERs present a stark contrast between the future visions for distributed energy and today's market realities, claiming that today's reality can be sobering. Developing business models that make this future vision a reality is proving difficult, with existing industry structures and disinterested customers just two examples of why practical applications are often confined to niche markets.

Where does the truth lie? And most importantly, what will the future power system look like? Mostly distributed or still predominantly centralized? In my view, a profound transformation of power systems is unavoidable and has already begun. But the endpoint will neither be a fully distributed nor the old, well-known centralized system. It will be a combination of both, a mixture of dispatchable and nondispatchable electricity sources, with the prevailing key words integration and flexibility. The extent and pace of this transition may be different from one country (or market) to the next, which will also determine the penetration of DERs in different contexts.

First, let us consider some facts and numbers about trends in distributed generation, for example, solar PVs. Solar PV additions in 2017 rose faster than any other fuel, including coal, natural gas, or wind. According to the 2018 Renewables Market Report (REMR) prepared by the International Energy Agency (IEA), solar PVs will continue to be the absolute leader of power capacity growth in the coming years. Solar PV capacity is forecast to grow by 600 GW (a larger expansion than that of all other renewable power technologies combined), reaching 1 TW of cumulative capacity before 2023.

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Distributed generation drives solar PV growth; without it, the level of increase for solar PVs would be comparable to that of wind. From 2018 to 2023, nearly half of PV capacity growth will be in distributed applications, of which commercial and large-scale industrial projects, residential systems, and off-grid installations account for 70, 28, and 2%, respectively. Distributed solar installations are expected to generate over 500 TWh, i.e., 40% of global solar PV electricity by 2023. This means that homes, businesses, and large-scale industrial applications will generate roughly 2% of global power output by the end of the forecast period.

The primary reason for this spectacular growth is massive cost reductions. PV levelized generation costs are forecast to be three to seven times lower in 2023 compared to those in 2011, depending on location and market conditions. But other factors are critically important as well for the economic attractiveness of distributed PV, such as retail electricity prices, remuneration schemes of excess generation, and economic incentives.

Distributed PV growth is driven by 1) self-consumption (i.e., electricity bill savings) in countries where average generation costs of distributed PV systems are lower than the variable portion of electricity prices and 2) a good match between consumption patterns and PV generation. This is the case for residential systems in Australia, Italy, and Spain and less so in Germany, despite very high electricity tariffs. However, the economic attractiveness of self-consumption business models remains limited where retail electricity prices are subsidized, such as in India, China, and

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Mexico. In these countries, financial incentives and remuneration schemes in which surplus electricity is injected into the grid are key factors in assessing the profitability of distributed PV projects. Commercial PV systems offer a better match between supply and demand, leading to self-consumption ranges up to 50%, depending on demand profile and the size of the PV system.

The economic attractiveness of distributed PV strongly depends on electricity tariffs but also on the manner in which surplus electricity is remunerated, which can range from zero to values higher than retail electricity tariffs, depending on national or subnational policies. Globally, more than half of the distributed PV generation capacity scheduled to come online from 2018 to 2023 is expected to receive fixed tariffs that could be higher or lower than retail tariffs. One-third of the distributed capacity is expected to fall under classic net-metering schemes, in which owners receive retail tariffs for surplus electricity. In some countries or markets (e.g., in the majority of Australian provinces, in some U.S. states, and in several European countries for large commercial installations), surplus PV electricity is bought with a value-based tariff imposed, whereby utilities or regulators estimate the value of PV generation based on avoided generation capacity expansions and any additional costs or benefits to the system or society (such as grid integration costs and carbon dioxide reduction value). Typically, value-based tariffs are between retail tariffs and wholesale electricity prices, usually closer to the latter. Remunerating excess electricity at wholesale prices is uncommon, as is distributed capacity with no remuneration of excess electricity, because expanding distributed PV capacity is challenging if remuneration for surplus electricity is low or nonexistent. These examples demonstrate that the pace of DER growth is not just determined by technological progress and cost reductions but remains significantly influenced by policies, market design, and electricity tariff structures. The other key variable is the attitude of market actors, particularly incumbent utilities.

The IEA 2018 REMR states that, in 2017, utilities were unable to collect an estimated US$3.5 billion in revenues (excluding tax) because of consumption of self-generated solar PV electricity in residential and commercial segments. This sales loss is expected to rise to more than US$12 billion annually by 2023, as distributed generation expands rapidly in China, the United States, the European Union, and Japan. While this is a large number, it equals less than 0.3% of the total current retail bill collection revenue worldwide. However, utilities in some countries, states, or provinces will be more affected than others depending on the amount of local distributed PV generation.

When discussing DERs, energy demand trends are as important as supply. A variety of emerging end-use technologies is transforming power systems around the world. In many cases, these end-use technologies enable greater flexibility in power systems and lead to higher demand for clean generation sources, such as variable wind and solar [e.g., electric vehicles (EVs), heat pumps, and smart and efficient buildings]. At the same time, the uptake of these technologies is bound to increase the complexity of overall grid operations, thus requiring new approaches to system operation and planning.

EVs are growing exponentially worldwide. Global sales of electric cars increased by more than 50% in 2017, reaching a record sale level of 1.1 million, and leading to a fleet of more than 3 million EVs. The electricity demand incurred from EVs is expected to triple by 2023.

Fleets of EVs can absorb excess variable renewable energy (VRE) when it is available, e.g., through smart charging protocols. They can also serve to balance load, reducing the need for often expensive peaking generation capacity. Serving as a new source of consumer demand, EVs could also help overcome the difficulties that utility business models face because emerging technologies such as rooftop solar and other DER options can decrease utility revenues. However, the widespread deployment of EVs without smart charging technology could create new challenges for system operators if low-voltage power lines become overloaded or if charging occurs predominantly during peak hours.

Globally, buildings account for roughly 40% of the total primary energy demand. New approaches to building design, operation and management, information technology, and end-use technology offer substantial opportunities for lowering energy usage while improving the comfort, health, and safety of building occupants. Smart and efficient buildings can also enable power system transformation by providing flexibility to the grid through aggregated demand response, reduced peak loads, and engaged energy consumers. End-use technologies include controllable thermal loads, such as air conditioners, heat pumps, or electric water heaters. For example, electric heat pumps have the potential to displace fossil fuels and provide highly efficient delivery of heating and cooling services. As with the smart electric charging of vehicles, electric heat pumps can be aggregated to provide additional flexibility to the power system by delaying or accelerating heating and cooling depending on grid conditions and utilizing the thermal storage inherently available in the residences or facilities they serve. Like EVs, electric heat pumps can increase electricity demand and help address lost revenues at utilities whose service areas include growing quantities of DERs. However, in the fossil fuel sector, electric heat pumps can lead to lost revenue and potentially stranded assets. Heat pumps are also used to increase flexibility as part of district heating systems by making use of their underground storage capacities.

The third major technology trend is the digitalization and smartening of grids. Smart grids comprise a broad mix of technologies for modernizing electricity networks, extending from the end user to the distribution and transmission levels. Improved monitoring, control, and automation technologies can help enable new business models while unlocking system-wide benefits. These benefits include reduced outages, improved response times, deferral of investment in the grids themselves, and the integration of DERs.

At the distribution level, making energy systems smarter through information and communication technology allows for optimization of grid monitoring and control. In particular, data and analytics allow for the real-time monitoring of conditions, opening up possibilities for predicting failures and carrying out remote maintenance.

At the end-user level, smart grids enable demand flexibility and consumer participation in energy systems, including through demand response, EV charging, and self-produced distributed generation and storage. Smart meter deployment has grown rapidly (with 800 million smart meters installed worldwide by the end of 2017) and has taken great strides in a few key regions. China is approaching full deployment, and Japan, Spain, and France are poised to reach full rollouts over the next few years. The United States and the European Union combined have reached over half of the market.

Investments in smart grid technologies grew by 12% between 2014 and 2016, but key areas such as smart distribution networks are lagging behind, with investment growing by only 3% in 2017. Progress in smart meter deployment is uneven across countries, with further regulatory change and new business models needed for smart grids to play their critical integration role in clean energy transitions.

Digitalization can bring many important advantages. For example, enhanced communication and control enable third-party aggregators to bundle the demand response of a portfolio of small end users. In certain markets, it is already possible to bid aggregated demand response flexibility into system services markets. As sector coupling advances, digital energy management systems (EMSs) can cooptimize the flow of power, gas, and heat in response to prices and consumers' demand for services. In combination with DER technologies such as intelligent connected appliances and battery storage systems, EMSs can open up substantial opportunities for demand response. However, barriers impeding the effective participation of end users as both consumers and producers of electricity and heat must be addressed. In many cases, third-party aggregation of end users is not allowed at all.

Digitalization also brings new challenges, e.g., data ownership and privacy. As new business models evolve, behavioral data linked to electricity consumption become a value source. Smart grid demand response technology allows (and requires) the widespread collection and analysis of vast quantities of consumer-specific, real-time electricity usage data. This may include records of individual energy-use events, such as heating water for a shower. Issues of data ownership and access will become increasingly important, particularly regarding the data privacy and security of individual end users.

All three of these technology trends, distributed generation, distributed end-use technologies enabling flexibility, and digitalization, call for a paradigm shift in how local networks are planned and operated. The breadth and depth of this transformation are often underestimated and will ultimately determine the pace of penetration of DERs. A successful transition must address a number of issues at three dimensions: technical, economic, and institutional.

The main issue at the technical level is to ensure secure and effective system operations with a high degree of decentralization. DERs may cause more dynamic energy flows, possibly posing challenges that require technical and operational changes. New modeling tools and greater collaboration between planners at all voltage levels will be critical for better management of bidirectional energy flows between transmission and distribution grids. This calls for a realignment of roles and responsibilities between system operators at different levels.

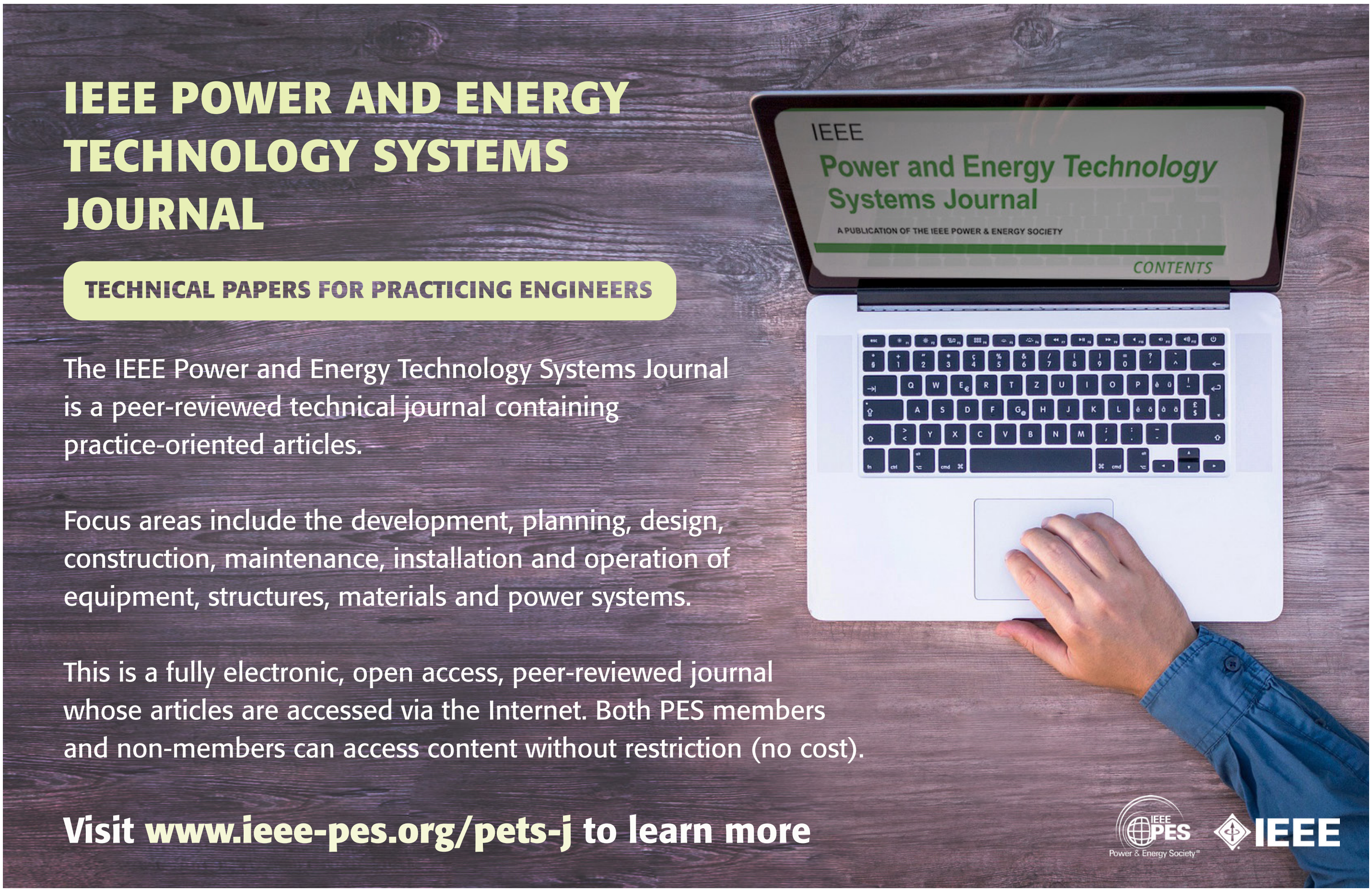
Planning practices must change as well. Historically, local grid planning followed a deterministic process aimed at identifying when and where peak load would occur. Rising levels of DERs introduce new uncertainties because these technologies bring a more complex supply/demand pattern to the grid; as a result, events that determine the necessary size of the grid may not coincide with peak electricity demand. Updated planning standards and more sophisticated modeling tools will be necessary, notably with the high-resolution representation of distributed generation resources, new approaches to demand forecasting that account for both controllable and noncontrollable loads, and the inclusion of multiple types of end-user load profiles, such as a home with an EV.

The main economic challenge is to ensure economic efficiency and social fairness through compensation mechanisms and retail rate designs. Retail electricity pricing was originally developed on the assumption that customers did not have any alternatives to grid supply and electricity demand was relatively inelastic. In this context, primarily volumetric price recovery was applied, with single per-kilowatt hour (kWh) tariff charges designed to recover most or all network and energy costs, including the supplier margin and energy taxes. The absence of tax reform, and penalties for increases in distributed solar PVs, create a strong motivation to use self-generated power directly or store it locally. This, in turn, lowers network flows and creates associated revenues for the grid owner. Over time, this translates into higher per-kWh prices for grid consumption for those who do not adopt DERs because the burden of network cost recovery is divided over a shrinking group of customers, thereby posing the issue of distributional fairness among different end users.

Additionally, increasing sector coupling (e.g., electrification of heating and transport) will increase the need for a level playing field among different resources, whereby energy services are priced similarly and subject to comparable taxes and levies. Finally, DERs may provide system services that are not captured at all in current tariff designs. This creates a need not only to consider reform of retail tariffs but also of valuation frameworks for DERs more broadly. More sophisticated tariffs that better reflect the supply–demand balance and locational constraints will be needed,

As mentioned previously, different remuneration structures for distributed generation that is not self-consumed greatly influence the economic attractiveness of distributed solar PV systems. Fixed remuneration (per unit of energy) provides investment certainty, whereas variable pricing can more effectively encourage system-friendly VRE design choices that maximize self-consumption or production during certain hours of higher system demand. Two types of value of solar (VoS) tariffs are emerging. The first assigns fixed-price tariffs based on an assessment of value components, including energy services, grid support, and fuel price hedging. Minnesota was the first state to adopt a VoS tariff, with its 25-year inflation-indexed tariff determined by cost-benefit analysis and an extensive stakeholder consultation process. The second category of value-based DER compensation involves more granular DER tariffs that reflect market conditions at specific times and locations. Adding price variability based on time and location can contribute to lower system costs by sending appropriate price signals to DER customers.

The need for designing enhanced tariff systems has important implications for policy making, which must carefully assess tradeoffs of different options, balance the costs and benefits of higher granularity, and address potential issues of social equity and cost distribution. Moreover, customers, regulators, and third parties all benefit from simplicity. For example, the effectiveness of time-based price differentiation is likely to be more effective than locational price differentiation; consumers can adjust their consumption throughout the day but typically have minimal ability to compensate for their location in the electricity network. On the other hand, new market actors



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emerge. In Germany, virtual power plants are used to aggregate many DER systems and sell their cumulative excess power in real-time electricity markets. The balancing responsibility is shifted away from individual DER customers to aggregators who can better manage this risk and respond to market prices with a portfolio of DER clients. Last but not least, increasing penetration of DERs requires revisiting roles and responsibilities. Historically, the interface transmission and distribution grid operation was managed in a clear, top-down fashion. Today, this is no longer the case. For example, transmission system operators (TSOs) in Germany rely on aggregators of small-scale dispatchable generators connected at the local grid level to obtain operating reserves. However, these reserves may not be available if congestion is being experienced at the local grid level at that moment. This example highlights the need for clear rules and responsibilities.

Other institutional reforms are needed to accommodate new commercial relations. To promote competition, aggregators or smart solution providers must have the ability to obtain confidential access to consumers fully independently of suppliers, similar to how it is done in France. The ownership and management of data are critically important to ensuring nondiscriminatory access to data and appropriate communication formats with customers while respecting data privacy. A forum for data exchange can be centralized like it is in Denmark, where the TSO Energinet is designated this task, or in the United Kingdom and Australia, where an accredited third party is responsible for data management. An alternative, decentralized model is based on the evolution of local grid companies and operators into neutral facilitators of local electricity markets, where DERs can offer energy and system services on a level playing field, e.g., the Reforming the Energy Vision process in the state of New York.

In conclusion, it is true that distributed generation is on an exponential rise, driven particularly by spectacular cost reductions of solar PVs. Costs are expected to continue decreasing as technology continues to improve and PVs increasingly become standard components of building construction. However, this is not sufficient for ensuring a successful and rapid transition to an energy system mainly based on distributed energy. This transition will require time and must address a set of key issues.

The narrative must be changed from simply distributed generation to integration and matching of customer service needs as well as flexibility options. Customers need reliable, affordable, and clean energy services. If supplied at the distributed level, these services must provide the flexibility to integrate large shares of variable, renewable power in a cost-effective and reliable manner while ensuring electricity security at all times. Important technological progress is ongoing in energy end-use technologies that can provide flexibility, e.g., EV's, heat pumps, and smart buildings. Moreover, improved prospects for new and less expensive battery concepts are fostered by unprecedented research development and deployment efforts, creating new avenues for the cost-effective integration of variable renewables and distributed generation.

However, technology alone will not finish the job. Systemic change is needed in the way power systems and low- and medium-voltage grids operate, away from the paradigm of passively distributed power to customers and toward smarter, actively managed systems with bidirectional flows of power and data. A successful transition will require due consideration of all three key dimensions: technological, economic, and institutional.

All of these factors will significantly determine the pace of the transition and how far a distributed energy future could go, which remains an important uncertainty. It is certain, however, that energy systems must be more integrated to absorb substantially larger shares of renewables. Power systems will need to embrace all forms of flexibility, from stronger grids and interconnections, more flexible power plants, affordable storage, and demand-side response. Most importantly, they will need the right market design and institutional settings to unlock this flexibility potential.

This is why, in my view, we will see a combination of dispatchable and variable generation, centralized and distributed, still for several decades. This is most likely the best combination for minimizing system costs while enhancing energy diversification and ensuring energy security.

Policy makers and regulators will have a crucial role in this transition; however, it would be a mistake to think that DERs will overhaul centralized systems and dominate the global energy mix in a few years. But it would be an equally important mistake to underestimate the disruptive tilting factor of distributed energy technologies when they become available and affordable to billions of customers and are perceived as simple and reliable.

It is up to the experts, from scientists and engineers to international organizations like the IEA, to provide guidance to policy makers to drive the transition in a balanced, secure, and cost-effective manner. This is, in my view, the best way to achieve a more sustainable (i.e., secure, clean, and affordable) energy mix that the world urgently needs.

For Further Reading

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