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ANNUAL REVIEWS

Annual Review of Environment and Resources

Facilitating Power Grid Decarbonization with Distributed Energy Resources: Lessons from the United States

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Annu. Rev. Environ. Resour. 2021. 46:349–75

First published as a Review in Advance on July 2, 2021

The *Annual Review of Environment and Resources* is online at environ.annualreviews.org

https://doi.org/10.1146/annurev-environ-111320-071618

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Keywords

distributed energy, renewable energy, demand response, utility regulation, market strategy, United States

Abstract

Decarbonizing power grids is an essential pillar of global efforts to mitigate climate change impacts. Renewable energy generation is expected to play an important role in electricity decarbonization, although its variability and uncertainty are creating new flexibility challenges for electric grid operators that must match supply with constantly changing demand. Distributed energy resources (DERs)—including distributed generation, demand response, and distributed energy storage—can play an important role in providing the flexibility needed to integrate high penetrations of renewable energy. This article examines federal and state enabling policies and regulations for DER, market strategies and business models that have facilitated DER expansion, and key emerging challenges for DER in the United States. Based on a review of the US experience, the article offers lessons for other countries, focusing on the role and limits of policy, the facilitative role of utility regulatory reform, the need to balance different interests in tariff design, the benefits of DER participation in wholesale markets, and the importance of proactive interconnection policies.

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Contents

1. INTRODUCTION

A growing body of evidence suggests that the electricity sector will play a pivotal role in achieving carbon-neutral energy systems by approximately the middle of this century, in line with the Paris Agreement's 1.5°C target (1–4). Globally in 2018, 30% of CO_2 emissions were a result of coal-fired generation (5). Decarbonizing electricity systems to meet mid-century carbon neutrality goals will, therefore, likely require a rapid increase in nonfossil electricity generation over the next decade (1). Across many countries, renewable energy resources are expected to be the most scalable near-term sources of nonfossil generation (1–4), although their integration into power systems continues to pose market and operational challenges (6–8).

Globally, renewable energy is already playing a significant and growing role in electricity systems. The world's renewable energy power generation capacity more than doubled from 1,223 GW in 2010 to 2,532 GW in 2019 (9). Wind and solar account for most of the recent growth in renewable generation. The installed capacity of wind energy increased from 181 GW in 2010 to 622 GW in 2019 while the installed solar photovoltaic capacity increased significantly from 40 GW in 2010 to 579 GW in 2019 (9).

The United States is among the world's fastest-growing countries in terms of both renewable installed capacity and power generation (10). Renewable electricity generation in the United States doubled from 2008 to 2018, with wind and solar generation accounting for the majority of growth (11). As a result of rapid growth, the share of nonhydro renewable generation rose from 3% of US electricity generation in 2008 to 10% in 2018 (11, 12). The share of renewable generation is expected to continue to grow in order to meet state-level renewable energy targets and state and federal climate goals.

Approximately half of the growth in renewable energy deployment in the United States can be attributed to state-level renewable energy targets (13). As of 2019, 13 states as well as Washington, DC, and Puerto Rico had either enacted legislation or issued executive orders with a commitment

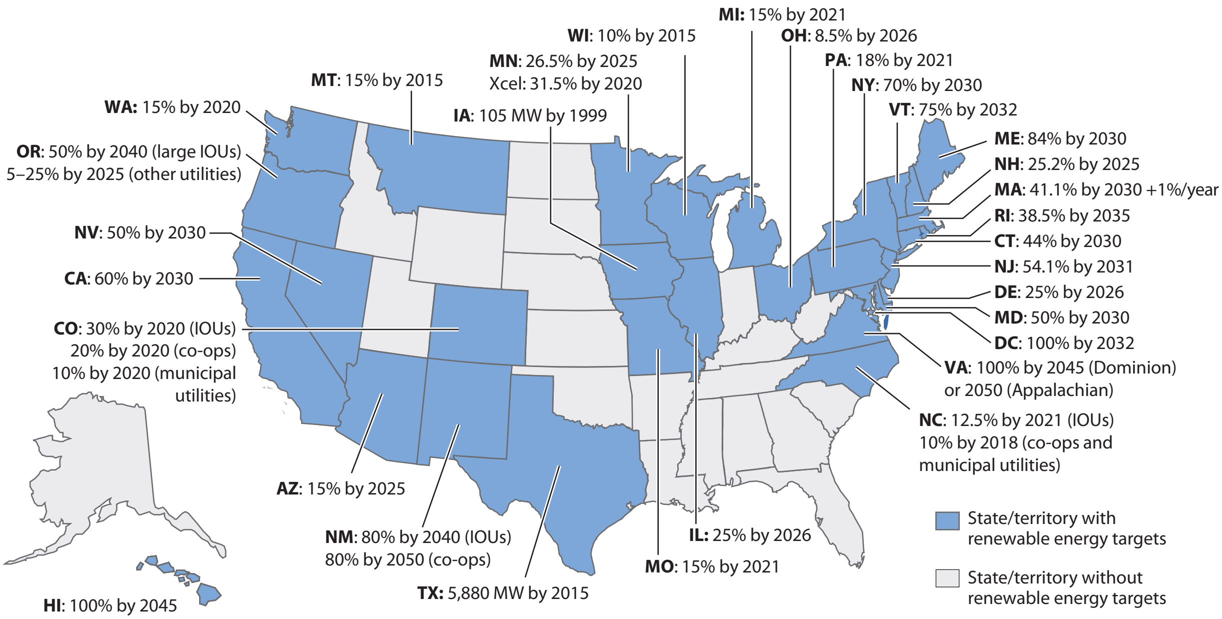

Figure 1

Renewable energy targets in US states and territories. Target percentages represent the sum total of all renewable portfolio standard (RPS) resource tiers, as applicable. In addition to the RPS policies shown on the map, voluntary renewable energy goals exist in numerous US states, and both mandatory RPS policies and voluntary goals exist among US territories (American Samoa, Guam, Puerto Rico, US Virgin Islands). RPS policies exist in 30 states and DC, which applies to 58% of total US retail electricity sales. Figure adapted from Reference 13 with permission. Abbreviations: IOUs; investor-owned utilities; co-ops, electric cooperatives; MW; megawatt.

to achieving either 100% renewable energy or 100% clean energy goals (14).[1] **Figure 1** shows state-level renewable energy targets adopted across the United States by the end of 2019.

Despite ambitious renewable energy targets, major obstacles must be overcome to enable future energy systems to economically and reliably operate with high penetration of variable renewable energy (VRE). As the US Department of Energy points out, "[o]ne of the greatest challenges to integrating VRE lies in managing its effects (variability, uncertainty, location specificity, nonsynchronous generation, and low capacity factor) on grid operations and planning" (15, p. 61). With the large-scale deployment of wind and solar generation on both the grid side and customer side, transmission system operators and distribution utilities face new operational challenges. Distributed energy resources (DERs) are emerging as a potential solution alongside traditional generation, transmission, and distribution infrastructure for addressing these challenges.

As the US Federal Energy Regulatory Commission (FERC) points out, there is no uniform definition of DERs, and the definition keeps changing (16). The US National Association of Regulatory Utility Commissioners (17, p. 45) broadly defines DERs to reflect their diversity:

> A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The

VRE: variable renewable energy

DER: distributed energy resource

FERC: Federal Energy Regulatory Commission

[1]For example, Hawaii was the first state to pass legislation for 100% renewable electricity by 2045. California has committed to increasing its renewable-powered electricity use to 60% by 2030 and achieving a 100% carbon-free electricity by 2045. Washington, DC, has the most aggressive target of achieving 100% renewable energy power supply as early as 2032.

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resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).

PV: photovoltaic

DR: demand response

DG: distributed generation

DERs have seen rapid growth in the United States. Distributed PV installations grew from 0.4 GW in 2010 to 10.5 GW in 2017 (18). According to data from the US Energy Information Administration (19, 20), the total existing small-scale storage power capacity connected to the US distribution network increased from 66 MW in 2016 to 234 MW in 2018. Among the capacity in 2018, 97% were behind-the-meter installations, and the share in the commercial, residential, and industrial sectors were slightly higher than 50%, 31%, and 15%, respectively. Demand response (DR), which is a program aimed at adjusting electricity demand "in response to price, monetary incentives, or utility directives so as to maintain reliable electric service or avoid high electricity prices (21, p. i)," has been active in the United States over the past five years. Between 2015 and 2019, the number of customers enrolled in DR programs increased from 9 million in 2015 to almost 11 million in 2019. At the same time, the actual peak demand savings averaged 12.2 GW per year, and the average annual power savings was 1357.4 GWh (22). Advanced metering infrastructure (AMI) is the foundation for the expansion of distributed energy systems. AMI is "an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers" (23, p. 4). The number of advanced meters increased from 58.5 million in 2014 to 86.8 million in 2018. Its penetration rate (the proportion of advanced meters in the total number of meters deployed in the United States) jumped from 38.8% to 56.4% in the same period (24).

The role of DERs as an electricity system resource has evolved over time. Historically, most DERs in the United States were demand-side management programs funded and administrated by utilities with the goals of cost-effectively reducing demand and enhancing utilities' interactions with their customers. These traditional programs focused primarily on energy efficiency and interruptible load management programs oriented around peak reliability needs.

Advanced DER applications go beyond traditional power system reliability needs to serve customers' growing interests in new, customer-sited applications such as distributed generation (DG), energy storage, load response, and managing electric vehicles while helping address emerging power system challenges. These challenges include the need to balance a large amount of solar and wind energy output that is neither constant nor fully predictable and the need to more actively operate distribution systems that have growing penetrations of customer-sited resources. Through bidirectional power flow, advanced system control, and real-time information flow, DERs are well suited to provide flexible resources to enable dynamic load adjustments to real-time operational conditions, thus improving the stability of the grid and enhancing grid flexibility for integrating VRE (25).

DERs offer numerous services and provide value to three different power system perspectives—regional system operators, utilities, and customers (see **Table 1**). Many of these services are critical for operating a stable and flexible electricity system powered by VRE (26). In addition to the benefit of grid flexibility, DERs could also play an increasingly critical role in improving power system resilience to deal with significant disruptions resulting from severe weather, deadly wildfires, and other extreme events (27).

This article examines US regulatory policy and implementation experience in deploying DERs to offer insights for the design of energy and climate policies and the potential role and challenges of DERs in decarbonization and improved power system resilience, in both the United States and other countries. The remainder of the article is organized as follows. Section 2 presents the framework through which this article reviews the US experience and lessons learned

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Table 1 DER services and value among different power sector stakeholders (15–17, 26, 28, 29)

Stakeholders	Services and value
Regional system operators	■ Energy arbitrage ■ Lower wholesale market prices ■ Spinning/non-spinning reserves ■ Frequency regulation ■ Ramping ■ Voltage support ■ Black start
Utility and transmission owners	■ Resource adequacy ■ Dispatchable resources, on both the utility and the customer side of the meter ■ Transmission congestion relief ■ Avoidance or deferral of new generation, transmission, and/or distribution investments ■ Peak demand shift or shed ■ Load following ■ T&D efficiency improvement due to reduced power losses ■ Reduced grid disturbances via islanding
Customers	■ Reshaping of customer load profiling ■ Time-of-use bill management ■ Self-supply of energy ■ Demand charge reduction ■ Compensation from DER program participation and performance, including net electricity exports ■ Backup power

Abbreviations: DER, distributed energy resource; T&D, transmission and distribution.

in adopting enabling policies and creating effective markets and business models for DER. Section 3 focuses on the role of specific federal and state policy measures in the United States in driving DER deployment. Section 4 discusses various market strategies and business models adopted in the United States in facilitating DER expansion. Section 5 describes major challenges and lessons learned thus far that may inform possible solutions in both the United States and elsewhere. Section 6 concludes the article with insights for other countries.

2. REVIEW FRAMEWORK

The literature on DER roles, policy, and integration is broad, covering the links between DER adoption and energy policy, permitting and interconnection rules, tariffs, and utility ownership structure (30–35); DER business and regulatory models (36); DER cost shifting implications and potential solutions (33, 37); and the role of DER in integrating renewable energy and enhancing grid flexibility (26, 38). Although many studies have focused on specific aspects and issues related to DER deployment in the United States, there is still a lack of a systematic review and organization in the existing literature on the use of enabling policies, market expansion strategies, and business model development for DERs. This article attempts to fill this gap.

Figure 2 shows an overall framework of the article. It starts by discussing enabling policies for DERs at the federal level, through changes in wholesale markets and federal research and development efforts, and at the state level, through resource planning and procurement, retail rate design, and changes in utility regulation. Next, the article examines effective market strategies and new business models that have been adopted in the United States for DER deployment that include DER monetization through power markets, reform of utility business models, and

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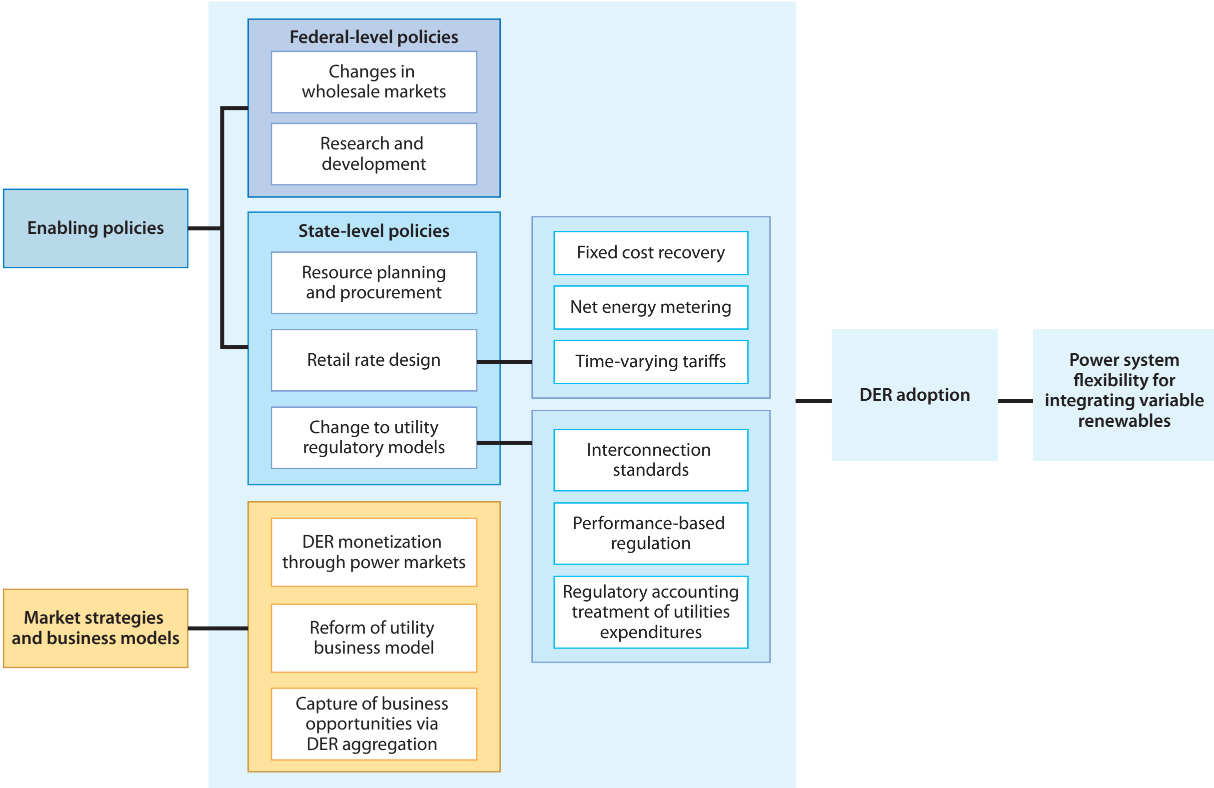

Figure 2

Illustration of review framework of distributed energy resources (DER).

capture of business opportunities through DER aggregation. The article concludes with lessons learned from the United States and insights for other countries to enable a wide DER adoption that helps enhance power system flexibility for integrating VRE. The remainder of the article is organized around this framework.

3. ENABLING POLICIES FOR DISTRIBUTED ENERGY RESOURCES

Federal and state energy policy and regulation in the United States evolved over many decades, resulting in a system of concurrent jurisdiction and a patchwork of state-level regulatory frameworks. For the electricity sector, regulatory jurisdiction is largely defined by wholesale and retail electricity markets. FERC has jurisdiction over wholesale electricity markets and high voltage transmission systems, whereas retail electricity markets and distribution system regulation are left to the states. The growth of renewable energy and DERs has occurred in both the wholesale and retail markets, creating jurisdictional challenges. However, states have greater jurisdiction over the regulation of distribution networks, where barriers to DER deployment are likely to be more pronounced.

Because of this split regulatory jurisdiction, enabling policies for DER have come from both a federal level, through changes in wholesale markets regulations and federal research and development efforts, and a state level, through changes in resource planning and procurement, utility regulation, and retail tariffs. The evolution in electric utility regulatory policy to accommodate DERs highlights, in part, the inherent flexibility of US electric utility regulation (39).

ISO: independent system operator

RTO: regional transmission organization

NWA: non-wires alternative

3.1. Federal-Level Policies

In the United States, federal policies have been adopted with a series of foundational FERC orders and federal legislation to support the emergence and growth of DERs. FERC orders generally unbundled transmission from generation services and required nondiscriminatory transmission access. FERC orders also established independent system operators (ISOs) and regional transmission organizations (RTOs) to operate regional wholesale markets, effectively creating competition in generation and transmission markets and encouraging nonutility (e.g., independent power producer) participation. Furthermore, FERC orders specific to DERs have removed barriers to participation of DERs in wholesale power markets and facilitated DERs through more open and coordinated planning and requirements to consider non-wires alternatives (NWAs) in transmission planning. **Table 2** lists key federal legislation and regulations that have paved the way for an accelerated deployment of DERs.

Although not specific to regulation or policy, the US federal government has also addressed barriers to increased DER deployment through long-standing research and development efforts at the Department of Energy. These include the SunShot Initiative to reduce the total costs of

Table 2 List of federal legislation and regulations

Legislation and regulation (year)	Outcomes
Energy Policy Act of 1992 (1992)	Started the process of deregulating the US power industry; enabled independent power producers to participate in wholesale markets
FERC Order 888 (1996)	Mandated open and fair access to power transmission systems
FERC Order 2000 (1999)	Led to the formation of ISOs as operators of regional wholesale markets
Energy Policy Act of 2005 (2005)	Removed unnecessary barriers to participation of DERs in energy, capacity, and ancillary markets by customers and/or load aggregators at the retail or wholesale level; also required utilities make NEM available to customers
FERC Order 890 (2007)	Established an open, transparent, and coordinated transmission planning process; together with FERC Orders 888 and 2000, helped open transmission access to a broader range of market participants
FERC Order 719 (2008)	Opened up the opportunities for the participation of DR in wholesale markets; specially permitted load aggregators to bid DR on behalf of retail customers directly into organized markets
FERC Order 745 (2011)	Required that DR be compensated at the same market prices as generation resources
FERC Order 755 (2011)	Removed discriminatory and preferential frequency regulation compensation practices from RTO/ISO tariffs; frequency regulation resources compensated based on the actual service provided
FERC Order 1000 (2011)	Mandated that transmission owners must establish procedures to identify transmission needs that are public policy driven, bringing impacts on RE/DERs, as promotion of these resources are largely driven by federal/state energy policies
FERC Order 841 (2018)	Opened wholesale power markets to energy storage to allow it to participate in organized power markets as long as they are technically capable
FERC Order 845 (2018)	Reformed standardized generator grid interconnection process with revised definition of generating facility to explicitly include electricity storage

Abbreviations: DER, distributed energy resource; DR, demand response; FERC, Federal Energy Regulatory Commission; ISO, independent system operator; NEM, net energy metering; RE, renewable energy; RTO, regional transmission organization.

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solar and achieve a utility-scale solar cost of $1/W (40), the Duration Addition to electricitY Storage program to develop innovative energy storage technologies possible for stored energy to power an electrical grid for up to 100 hours (41), the Grid-interactive Efficient Buildings Initiative to reduce building consumption and improve building capabilities to provide grid resources (42), and the Energy Storage Grand Challenge that coordinates research effort targeted at storage-related technology development, technology transfer, and manufacturing and supply chains, among others (43).

3.2. State-Level Policies

Regulations governing retail electricity markets and distribution systems are established through state legislation and utility regulation. As a result, state-level regulatory and policy drivers of DERs are more fragmented and reflect states' different economic and legal frameworks. State-level policies for DERs broadly fall into three categories and address particular barriers to DER deployment. The three categories are resource planning and procurement, retail rate design, and utility regulation.

3.2.1. Resource planning and procurement. DERs tend to be disadvantaged relative to utility generation investments due to their smaller scale and deployment that is typically on the customer side of the meter. Regulators have developed and implemented a range of policies for more equal consideration of DERs with traditional utility resources in planning and procurement. More than three dozen states have integrated resource planning (IRP) or long-term planning requirements that specify the supply- and demand-side resources to meet future electricity demand (44). Many states have requirements that DERs be considered in utility IRPs (45, 46). In pace with rapid expansion of DERs, states are also increasingly paying attention to distribution-level resource planning. Utility regulators in Connecticut, Missouri, and Minnesota, for example, have proposed or started developing an integrated distribution energy planning process (47).

States have also established procurement or resource targets that help promote DER. A renewable portfolio standard (RPS) is a state policy widely used in the United States to require a certain percentage of the electricity sold by utilities to come from renewable sources in order to increase the deployment of renewable energy. Renewable energy certificates (RECs), which represent 1 MWh of renewable energy generation, are utilized to verify that utilities meet their targets (48). As a part of their RPS policy, some states have developed specific mechanisms such as REC multipliers, which offer more than one (or less than one) REC credit for electricity produced by certain technologies to target specific applications related to DER. For example, four states—Arizona, Nevada, Oregon, Washington—target distributed renewables in their credit multipliers, whereas Colorado and Maine focus their credit multipliers on community energy (49). Arizona and New York are among states that enacted an energy efficiency resource standard obligating electric utilities to achieve a mandated energy savings level. Several states have developed or are developing frameworks that require utilities to consider third-party-owned DERs as a NWA for conventional distribution infrastructure upgrades (50).

3.2.2. Retail rate design. This section provides an overview of recent policy efforts regarding retail rate design intended to address fixed cost recovery and compensation for net electricity export for DER systems. We discuss remaining challenges in Section 5.

3.2.2.1. Fixed cost recovery. Retail rate design in the United States has historically relied on flat, average volumetric energy charges to recover fixed and variable costs. DERs deployed on the customer side of the meter reduce utility energy sales and raise concerns among utilities about

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fixed cost recovery and revenue sufficiency (51). To address this challenge, regulators and utilities are beginning to offer residential customers three-part rates that include demand charges, along with volumetric energy charges and fixed customer charges as a means to address fixed cost recovery concerns and providing customers an incentive to manage their demands (52). There are many states that have proposed or adopted measures including raising residential customers' monthly fixed charges, placing minimum bills, or imposing a residential demand and solar charge. Notable examples include Arizona Public Service's voluntary residential demand charge rate options and Salt River Project's three-part rate for residential DG customers (53).

NEM: net energy metering

3.2.2.2. Net energy metering. The recent growth in distributed PV installations in the United States is attributed, in part, to net energy metering (NEM), which allows exported DER generation at one time to be netted against electricity consumption at a different time, thus compensating exported generation at the full retail rate (53). Certain states have instituted mandatory NEM thresholds or caps. For example, the State of Washington has required, as part of its clean energy legislation enacted in 2019, utilities to offer NEM to qualified customers until the cumulative power generation of connected systems equals 4% of peak utility demand (54). California also established a cap for NEM at 5% of aggregate peak electricity demand in 2013 for the state's three investor-owned utilities. However, two of them reached the thresholds in 2016 due to fast growth of DG installation (55).

NEM reforms have been prompted by states reaching statutory caps on NEM or concerns about cost-shifting between customers with and without DG. The cost-shifting is caused by compensating DG-exported generation at full retail rate during times when it is not providing utility system benefits commensurate with full retail electricity costs (56). Net billing that retains the netting feature of NEM but compensates exported DG generation at a price other than full retail rate has been the most common NEM alternative in the United States, and states have started developing more granular methodologies to properly value the DER contribution to the power system (51).

For example, Michigan has adopted a new cost of service–based DG program tariff, under which new NEM customers will be subject to an inflow/outflow billing mechanism and compensated at the utility-avoided cost rate for excess generation put back on the grid while they pay the full retail rate for the power purchased from the grid (57). The regulator in Hawaii has created price signals to link DG compensation to the value it provides to the grid by crediting DG owners depending on time of day. Under Hawaii's Smart Export program, energy exported to the grid during the daylight hours (9 am–4 pm) receives no compensation, whereas energy exported at other times (4 pm–9 am) is compensated (58). Programs like Smart Export will likely stimulate the market growth for distributed renewable plus storage combinations. New York has taken a step further to propose transitioning NEM to a new Value of DER tariff that compensates the DER's exported electricity based on its Value Stack, which focuses on the range of benefits DERs provide to the New York utilities' distribution networks (e.g., location-based marginal electricity price, capacity, environmental benefits) (59).

3.2.2.3. Time-varying tariffs. In the United States, regulators and utilities have developed time-based retail tariff programs to create clear price signals to enhance customers' load responsiveness to power system conditions and more closely align DER value with its value to the power system (60). **Table 3** describes various types of retail rate aimed at triggering load response from simple to more complex design.

3.2.3. Changes to utility regulatory models. Many states are exploring changes to existing utility regulatory models in response to increasing DER deployment as a means of minimizing

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Table 3 Time-varying retail rate designs in the United States

Programs	Description
Time-of-use (TOU) rate	TOU is a rate plan whereby electricity rates change based on the time of day or the season to better align the costs of operating the power system with power use. Utilities are starting to implement default residential TOU rate plans across the United States.
Critical peak pricing (CPP)	CPP is a more dynamic form of TOU price. It is event-based and in effect only when utilities anticipate high wholesale market prices or power systems experience emergency conditions. Utilities may call critical peaking events during a specified time period, and the electricity price during these events is substantially high. Participating customers are often offered a discount on their regular summer electricity rates in exchange for a higher price on a small number of CPP event days during the year. Some CPP programs allow customers to self-select a certain amount of capacity (in kW) to be exempted from the high price during a CPP event by paying a fixed monthly Capacity Reservation Charge upfront. During a CPP event, power usage protected under the customer's capacity reservation will not be subject to the CPP, whereas usage during a CPP event that is not reserved will be billed at the CPP.
Variable peak pricing	Variable peak pricing is a hybrid of TOU and RTP where the TOU periods are defined in advance but the price for the on-peak period varies by power system and power market conditions. It is different from TOU rates in that both the periods and rates for each period are predetermined and fixed. Programmable thermostats are often used by customers to better manage electricity use with variable peak prices, allowing customers to effectively respond to the price signals from the utility based on their preset preferences.
Real-time pricing (RTP)	Under RTP, customers are charged for the electricity use on an hourly basis, corresponding to hourly wholesale market prices. To participate in RTP, customers must have a smart meter installed that is capable of recording hourly power usage.

the potential disruption to grid operations (61) and realizing benefits to utilities and customers. These alternative utility regulatory models shift the roles, responsibilities, profit motivation, and profit achievement of electric utilities from building new, centralized generation assets to encouraging extracting value from existing assets to offer a range of energy services to customers (39). Section 5 discusses challenges in implementing alternative utility regulatory models.

3.2.3.1. Interconnection standards. Generation and storage that connect to the distribution system must be interconnected by a distribution utility. Distribution utilities typically do not have a natural incentive to interconnect customer-owned or third party–owned DG and storage resources because these resources may compete with utility resources, reduce utility revenues, or create reliability issues on the distribution system. Responding to these economic and reliability concerns, utilities may use the interconnection process to limit growth in DERs, by delaying interconnection or restricting access to the distribution system altogether (62). In the United States, a growing number of state regulatory commissions have established detailed rules and interconnection standards governing the timing and requirements of the distribution interconnection process (63, 64).

3.2.3.2. Performance-based regulation. State regulators across the country have proposed or implemented performance-based regulation to help align utility investment with policy goals and improve utility performance in specific areas, including DER investments, while also providing new utility earnings opportunities (65). For example, regulators in Minnesota established several performance metrics for guiding utility investment, including affordability, reliability, customer

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service quality, environmental performance, and cost-effective alignment of generation and load (66). Nevada regulators have started a ratemaking process focusing on measures such as performance incentives, decoupling mechanisms, and earnings-sharing mechanisms that help stimulate utility investment toward meeting the state's 100% clean energy goal (67). New York State's Reforming the Energy Vision (REV) allows distributed utilities to earn additional revenue on top of their cost-of-service earnings for enhancing distribution system performance with DERs and using them to replace conventional power grid investments (68). Specifically, the state has created earning adjustment mechanisms to incentivize utilities based on (*a*) power system efficiency assessed by a combination of peak reduction and load factor improvement, (*b*) energy efficiency that meets higher targets beyond the current one, (*c*) satisfaction of renewable DER providers in utility assistance in grid interconnection, and (*d*) customer engagement tied to customer uptake in specific programs (69).

Reforming the Energy Vision (REV): policy initiatives launched in the State of New York to spur investment in energy efficiency, renewable energy, DERs, and smart grid

3.2.3.3. Regulatory accounting treatment of utilities expenditures. In the United States, traditional cost-of-service ratemaking has allowed regulated utilities to earn a return only on capital expenditures. DERs can replace capital expenditures, reducing utilities' total investment returns under existing ratemaking. To allow utilities to capture new opportunities in integrating DERs and earning a return on them, some US state regulators have started to address regulatory accounting treatment of utilities expenditures. Specifically, some regulators are allowing expenses that can cost-effectively offset capital investments to be treated as regulatory assets, thus eliminating utility disincentive in pursuing more cost-effective options (70) and delivering better value to customers.

For example, the Illinois Commerce Commission initiated a rulemaking process to establish regulatory accounting for regulated utilities that would create more equitable treatment for new service solutions, such as software as a service, platform as a service, and infrastructure as a service (71). New York created NWA shareholder incentives that treat a utility's costs of acquiring third-party DERs as a regulatory asset and allow utilities to recoup the costs. In addition to cost recovery, utilities in New York are also offered a shareholder incentive that amounts to 30% of the difference between the net present benefits of DERs and the traditional solutions replaced by NWA (72). California created a DER Adder enabling regulated utilities to receive 4% on expenses each year for missed earnings on traditional infrastructure assets (73). The above-discussed change of regulatory accounting treatment and other regulatory changes create new utility business models, discussed below, that could further facilitate DER expansion.

4. EFFECTIVE MARKET STRATEGIES AND NEW BUSINESS MODELS FOR DISTRIBUTED ENERGY RESOURCES

4.1. Monetizing Distributed Energy Resources Through Power Markets

In the United States, federal rulemakings (i.e., FERC Orders 719, 745, and 841) have opened wholesale power markets to DERs, allowing these resources to participate in organized power markets, as long as they are technically capable, and to be compensated at the same rate for other competing generation resources. As FERC pointed out, technology advances have transformed DERs from a "passive do no harm" resource to an "active support reliability" resource to support the bulk power system (16).

There are numerous existing and emerging ways for DERs to participate in ISO markets, and this varies across the country, depending on the design of each ISO/RTO market. For example, this may involve participating in capacity markets, energy markets, or ancillary service markets. These market opportunities have had an important influence on DER growth in the United States.

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Many DER providers in wholesale markets in the United States are compensated through a capacity payment in the capacity markets that includes a fixed monthly payment plus a pay-for-performance compensation for delivering the committed resources. Capacity markets may create more certain value for DERs due to the upfront payment (74). DERs can also participate in the energy market but the requirement of more frequent dispatch and lower payment in the energy market than in capacity markets make it much less attractive for DER providers. Ancillary services require rapid response and generation-grade telemetry, thus limiting the pool of capable DER providers without automated control (75).

T&D: transmission and distribution

It is worth paying attention to the interactions and differences between different markets. The capacity market equipped with pay-for-performance compensation and nonperformance penalties helps address system peak and enhance overall power system reliability and price stability, but it may also bring down energy and ancillary service market prices, reducing the value for flexible resources, such as DERs, whose values rely heavily on short-term operational fluctuations and price volatility (76). Concepts and proposals for a new framework for ancillary service markets has been discussed in order to better value flexible resources (77).

It should also be noted that whether DERs participate directly or not in RTO/ISO markets could have different impacts on the operations and planning of the bulk power system (78). As pointed out by FERC (16), DERs participating indirectly through retail net metering may lead to a lack of real-time visibility of DERs in the bulk power system—lack of both static data on the location, size, and technological capabilities of DERs and DER telemetry data such as output—which may prevent RTOs/ISOs from accurately evaluating bulk power system conditions and behind-the-meter generation in real time. Challenges like this are reviewed further in the DER wholesale market integration discussion in Section 5.2.

DER providers can also find market opportunities by participating in utility wholesale procurements. For example, California has piloted a Demand Response Auction Mechanism program, which allows utilities to meet their resource adequacy obligations by competitively soliciting DR system capacity, local generation capacity, and flexible capacity at megawatt scale from third parties who can then bid their aggregated DERs directly into the California wholesale market (79).

4.2. Reforming Utility Business Models

In the United States, increased penetration of DERs has resulted in noticeable changes in utility business models to better align utility profits with public policy objectives and energy transition efforts. With regulatory reforms that would allow utilities to earn a regulated rate of return on DERs, new utility business models are emerging or being proposed. For example, nearly a dozen investor-owned or municipal utilities directly own and operate DERs—mainly rooftop PV. Compared with customer or third-party ownership, the utility ownership model has multiple benefits. For example, utilities maintain a higher level of electricity sales and collected revenues while receiving additional earnings from rooftop solar investment that more than offsets reduced earnings from generation and transmission and distribution (T&D) capital expenditure deferral. The siting flexibility also allows utilities to target specific geographic locations that could lower utilities' costs of meeting customer loads or provide better services to underserved communities. In addition, the utility ownership model enables utility planners and operators to have better visibility and control over DER assets, thereby improving grid operation efficiency (80).

Under other models, utilities would operate the distribution grid as a market-facing service platform, "akin to an air traffic controller that coordinates and facilitates the deployment of various distributed energy resources (DERs) on the grid" (81). The platform would allow customers and third-party DER service providers to build and operate DERs to enhance the reliability and

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flexibility of the power grid with high renewable penetration while creating better value for utility customers and delivering new revenue streams for utility shareholders.

One of the most comprehensive changes to utility business models is occurring in New York. Under the state's REV framework, regulated utilities would transition their role from a distribution network operator to a distributed system platform provider with three types of functions: (*a*) responsible for integrated system planning aimed at supporting the development of DER alternatives to help meet current and future power system requirements; (*b*) in charge of distribution network operations to integrate DERs into the current electricity delivery system for an optimized, secure, and more flexible power system; and (*c*) being a single and uniform market platform of linking customers and DER providers and facilitating retail interactions with the wholesale market as an aggregator of aggregators (82).

To allow utilities to better provide platform services and increase DER integration, several state regulatory commissions (e.g., California and New York) have required regulated utilities to develop interactive hosting capacity maps that illustrate where utilities can accommodate new DG on the distribution system without upgrading the existing infrastructure and made this tool and information available to DER system owners (83). These efforts are intended to provide insight into the location-specific DER integration and to encourage third-party DER providers to target those areas.

With the large-scale deployment of smart metering infrastructure, continuing grid modernization, rapid development of Internet-of-things, and widespread use of artificial intelligence, utilities are in a strong position to take advantage of tremendous amounts of customer data and leverage connectivity across their service territories to continuously create new revenue streams.

4.3. Capturing Business Opportunities from Distributed Energy Resource Aggregation

With expectation of continued growth, many thousands of behind-the-meter DER systems will need to be aggregated and coordinated with the support of advanced information, communication, and automation technologies to provide capacity and ancillary services needed by the distribution grid. In the United States, third-party DER aggregators have emerged to serve as intermediaries between end-use customers and the utility to play a significant role in effectively managing several individual DER systems to form a sizeable grid resource—often referred to as virtual power plants—that can be bid into the wholesale power markets or procured by distribution utilities.

There are numerous revenue-generating opportunities that have recently emerged for DER aggregators. DERs that consist of various resources, including DG, energy storage, and DR—when used in combination—can deliver a variety of values to the power system. Aggregating these resources to stack services can create multiple value streams for the aggregators while benefiting the power grid, distribution utilities, and customers (84, 85). Combined use of various DER technologies with complementary capabilities helps mitigate limitations caused by relying on individual technologies alone.

In the United States, third-party DER aggregators can partner with utilities in providing grid services. Specific to DR programs, for example, aggregators are able to pool DR resources across a large number of customers and coordinate these resources in a way that ensures a specific level of energy and/or capacity is available to a utility or grid operator. In providing DR services to utilities (at the retail level) or grid operators (at the wholesale level), DR aggregators have a contractual obligation to deliver a certain amount of capacity if dispatched. They are responsible for all roles from customer acquisition, marketing, sales, retention, support, and event notification to customer resource dispatch, settlement, and compensation payments. Customers authorize the aggregators to act on their behalf with respect to all aspects of DR services offered to utilities (75).

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In other cases, aggregators are not responsible for operational aggregation but only on the installation and packaging (e.g., software control) side, with utilities responsible for the operational part. An example of this role played by third-party aggregators is a residential housing development project under construction in Utah. The project, which is owned by a real estate developer, is so far the country's largest residential virtual power plant project that bundles DG, DR, electric vehicles (EV), and battery storage and is controlled and dispatched to the grid by the local utility as needed. "[T]he planned community's 22 buildings will have 600 apartment units with 12.6 MWh of battery storage, 5.2 MW of solar panels, 150 stalls of EV chargers and an overriding focus on energy efficiency.... The 600 batteries can all work together as a hive to push the power that the grid needs at any given moment... will turn the complex into a grid resource" (86). This project could serve as a model of aggregated DER use in other areas.

According to data from the US National Renewable Energy Laboratory, 49% of households and 48% of businesses cannot install their own on-site photovoltaic solar systems because they live in leased properties or lack suitable roof space (87). The community shared solar projects that are connected to the distribution system help increase deployment of distributed solar. They attract customers who are unable to accommodate solar systems due to unsuitable roof space or cannot install solar systems due to living in a multi-unit building or renting properties and people who cannot afford the large upfront costs of solar systems. For participants (subscribers), the shared solar opportunity gives them the chance to invest in distributed solar projects by owning or leasing a portion of a community solar system located elsewhere and receive credits on their monthly electricity bills for their portion of the electricity generated by the community system (88). These projects could be developed and operated by various types of entities such as developers, landlords, homeowner associations, nonprofit organizations, etc., who could serve as an aggregator to offer services to utilities.

The PV subscription model can bring significant benefits to communities and utilities (36, 89, 90). For the former, the model expands the solar PV access to more people, enhancing affordability by sharing costs among numerous subscribers. The model can also help minimize inefficiency by preventing individuals from installing smaller solar systems to meet only their own needs and separately handling building codes, zoning restrictions, and other administrative burdens. In addition, the model offers participants great flexibility, allowing them to invest at the level that best suits their budget or to transfer the subscription to others when they move out or no longer want to own the subscription (90). For the latter, grid operators can take advantage of siting flexibility to install DERs at locations that have supply constraints or high price of electricity, thus optimizing grid operations (91). Such flexibility is made possible by the application of virtual net metering. Community shared solar can also enhance the efficiency of operating distribution networks by allowing network operators to coordinate community-scale DERs in a more streamlined manner compared to managing many smaller, dispersedly located individual DERs.

Despite their benefits, however, community DERs still need to tackle multiple issues, such as potential liability imposed by federal security regulation if the community system subscription is identified as a securities asset (92), as well as the challenge in acquiring PV investment tax credits and fairly allocating renewable energy credits with the complicated system ownership structure (93).

5. KEY CHALLENGES AND LESSONS LEARNED

Continued deployment of DERs in the United States—and ultimately the transition to a more active and flexible distribution system—currently faces several challenges. This section describes key challenges and lessons learned thus far that may inform possible solutions, in both the

United States and elsewhere. DER deployment challenges and lessons learned can be broadly grouped into three interrelated categories: (*a*) access and interconnection, (*b*) operations and markets, and (*c*) tariffs.

5.1. Distribution System Access and Interconnection

Even in states that have detailed DER interconnection rules, many aspects of DER access to the distribution system remain unresolved. Enabling more competitive access to the distribution system will require ongoing efforts to address institutional, organizational, and jurisdictional obstacles.

5.1.1. Key challenges. DER interconnection has historically been guided by two assumptions: (*a*) Utilities should not actively manage resources on the distribution system, or, phrased differently, exports from nonutility-owned DG and storage to the distribution system should not be dispatched by utilities; and, relatedly, (*b*) the distribution system should have the capability to allow all output from customer-owned DG and storage to be delivered to the distribution system.

As DER penetrations increase, upgrading distribution infrastructure to allow full resource deliverability will often not be the lowest cost solution. A more straightforward solution will be for distribution utilities to conduct some form of DER dispatch. For instance, for a PV system whose exports would lead to thermal limit violations in a small number of hours, downward dispatch (via curtailment or storage) would be a more cost-effective strategy than distribution upgrades. If utilities are able to effectively dispatch DERs, new DER customers can interconnect to the distribution system even if the system cannot accommodate their entire output.

Allowing distribution utilities to dispatch DERs will require some form of open access rules, akin to those that govern the transmission system in the United States. Open access rules for the distribution system would cover five key areas (94) (**Table 4**).

An open access framework would also entail significant changes in distribution system planning. Distribution infrastructure has historically been planned based on expected load growth. The emergence of dispatchable resources on the distribution system will require changes in planning methods and criteria.

Lack of clear regulatory jurisdiction between the federal and state governments is a key challenge in developing open access rules for the distribution system. As discussed above, interstate wholesale transactions are under the federal jurisdiction of FERC, while regulation of distribution utilities is generally under the jurisdiction of state regulatory commissions in the United States. Without clear jurisdiction, neither FERC nor state commissions have a clear motivation to develop open access tariffs at the distribution level.

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Table 4 Key areas covered by distribution open access rules

Key areas	Related questions
Access and interconnection	What are the costs and eligibility, technical, and credit requirements for interconnection?
Roles and responsibilities	What are the rules of conduct and standards for participants and operators?
Operations	What are scheduling/dispatch procedures, market products, and distribution dispatch rights?
Settlement and billing	What prices are used for distributed energy resource settlement, and how are transmission and distribution system billing coordinated?
Market oversight and dispute resolution	What organization(s) oversees distribution operations, and how are disputes between parties resolved?

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DSO: distribution system operator

5.1.2. Lessons learned. Some key lessons learned from the US experience in open access to and interconnection with distribution networks include the following:

- It is important to establish clear and detailed rules that govern interconnection timelines, costs, and technical standards.
- It is important to establish effective rules for access to distribution networks that clarify how distribution system operators (DSOs) will interconnect, dispatch, and settle nonutility-owned DERs connecting to the distribution system.
- Jurisdictional conflicts over distribution system regulation must be resolved, in order to provide better regulatory incentives for government agencies to develop proper access rules.

5.2. Operations and Markets

Distribution utilities in the United States have historically actively managed DERs only on a limited basis, primarily through interruptible load management programs. DERs have not been well-integrated into ISO markets. With rising DER penetration, there is a need for more active management of DERs through distribution operations and better integration of DERs into ISO markets.

5.2.1. Key challenges. Two key challenges for distribution operations and ISO market integration are basic control architecture (ISO-DSO) and ISO market design. **Figure 3** shows three potential options for DER operational architecture. In the first approach, all DERs participate directly in ISO markets through load aggregators who act as a DSO. The California Independent System Operator distributed energy resource provider program is an example of this approach. With higher DER penetration, this approach requires extensive coordination between the ISO and DSO (78), to ensure that DER schedules do not lead to operational violations on both the transmission system and the distribution system.

In the second approach, the DSO acts as a super aggregator, conducting security constrained economic dispatch for the distribution system and managing operational control and settlement at the ISO-DSO interface, rather than having the ISO extend its control and settlement into

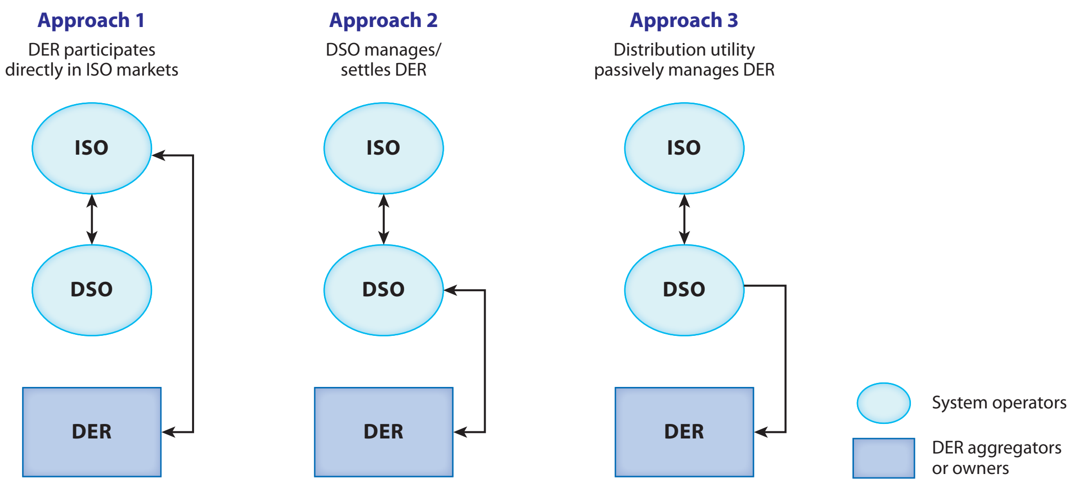

Figure 3

Three potential approaches to DER operational architecture: Interactions Between an Independent System Operator (ISO), a Distribution System Operator (DSO), and Distributed Energy Resources (DER).

the distribution system (95). In the third approach, distribution utilities only manage DERs in emergency (reliability violation) situations and settle DERs at retail rather than wholesale tariffs that apply to the first two approaches. Which of these three approaches will become the industry standard is still unclear, and different jurisdictions may take different approaches.

TOU: time of use

Having the DSO act as a scheduler and settler for DERs (the second approach) will require several changes in market design. These include changes in the following:

- Intraday energy market design that allows loads to change their schedules within the day, relative to the status quo where ISOs clear real-time markets with their own forecasts of demand;
- Settlement that allows at least some loads (DER customers) to be settled at locational marginal prices (LMPs), relative to the status quo where most customers are settled at aggregated LMPs;
- Capacity market design that provides tractable approaches to account for a large amount of small-scale resources, relative to current capacity markets that were designed for larger resources.

These changes are complex, requiring more sophisticated forecasting, control, market, and settlement systems. The United States is still in the early stages of developing and deploying these systems.

5.2.2. Lessons learned. The following are some key lessons learned from the US experience in integrating DERs into ISO markets:

- Developing operational control and market designs to support higher DER penetration is complex and will create significant challenges.
- Considering and implementing a vision for DERs in wholesale market design can lead to better outcomes, relative to attempting to retroactively adapt market design to DERs.

Creating new frameworks for valuing electric reliability will be important to enhance the value of DERs.

5.3. Tariffs

Utilities often act as wholesale market intermediaries for DERs, buying services from DERs and paying either on an average avoided cost basis (e.g., for cogeneration or DR) or using NEM (e.g., for distributed PV). Many DER customers are treated as retail, rather than wholesale, customers, with bundled tariffs—tariffs with supply (generation), delivery (T&D), and administrative (accounts, billing) charges rolled into flat volumetric ($/kWh), simple time-of-use (TOU) (on-peak/off-peak), tiered rates, or, for larger customers, volumetric and demand charges. Reconciling the wholesale and retail dimensions of DERs will require changes in tariff design.

5.3.1. Key challenges. For utilities, cost recovery is a primary concern for tariff design. DERs can reduce generation output and capacity factors for utility-owned generation, leading regulators to question the prudence of utility investments. DERs can also lead to bypass of generation and T&D charges, where customers reduce their T&D charges by reducing load or shifting it to other time periods. Because these costs are fixed, bypass leads to short-term cost under-recovery for utilities, before tariffs can be adjusted to account for lower demands, and longer-term cost shifting to other customers. Paying for DER exports to the grid using average avoided costs can also lead to overpayment, in cases where the value of DERs is less than wholesale costs.

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However, DERs can also have broad benefits for consumers by enhancing dynamic and productive efficiency. Economic bypass, where customers reduce loading on bulk generators and the T&D system during periods when the power system is constrained, is beneficial for all consumers because it improves dynamic efficiency—reducing long-run marginal costs via reducing the need for new generation and T&D investments—and productive efficiency—reducing system-wide operating (energy and ancillary services) costs.

Across the United States, there is a trend in shifting toward more accurate and sophisticated tariff designs, although the process has been contentious because of the potential for cost shifting between producers and consumers. Real-time data on customer use allows regulators to consider and propose more sophisticated rate designs. With higher DER penetrations, tariff design will require significant changes to balance utility cost recovery and the economic efficiency benefits of DERs (94, 96). These changes may include the following:

- Treating DER customers that export to the grid as wholesale customers that are settled using unbundled (separate generation, delivery, and administrative) wholesale tariffs, with the generation portion of the tariff set using market-based or marginal cost-based rates;
- More sophisticated, multi-part T&D rates for DER customers that include fixed network charges ($/month), to collect some historical costs, and fixed and volumetric charges that provide incentives for DER customers to change marginal consumption.

Historically, customers were not able to respond to more sophisticated tariff designs due to lack of enabling technologies. However, emerging information and communication technologies that enable customer response in real time have reached or will soon reach commercialization.

5.3.2. Lessons learned. The following are some key lessons learned from the US experience in designing more effective tariffs for DERs:

- Addressing tariff designs for DERs before penetration of these resources begins to rise can avoid creating entrenched interests and resistance to changes in tariff design.
- It is important to develop tariff designs that balance the economic efficiency benefits of DERs with fair utility cost recovery.

6. CONCLUSIONS AND INSIGHTS FOR OTHER COUNTRIES

DERs have the potential to transform existing electricity systems, thereby reducing power system infrastructure and operating costs, improving power system reliability and resilience, and increasing power systems' ability to integrate VRE (26, 97). The United States has seen rapid growth in DERs over the past several years, propelled by federal and state policies and regulations. State policies have been diverse, ranging from DER target setting to resource planning, changes of utility regulation, interconnection to the distribution system, net metering, and building codes, whereas federal policies have focused on facilitating opening access of DERs to wholesale markets.

Globally, several countries have set ambitious goals for renewable energy development in the next ten years. For example, the European Union pledged to achieve a 32% renewable energy target by 2030. The Indian government has committed to using renewable energy to meet half of the country's electricity demand by 2030, while China has pledged to increase the total installed capacity of wind and solar energy from 415 GW in 2019 to 1,200 GW by 2030, so that nonfossil energy accounts for 25% of the country's primary energy consumption (98–100). Many countries face challenges that are similar to those in the United States in enhancing the flexibility of their power systems to integrating high penetrations of renewable energy.

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This article distills five key insights from the US experience with DER policy and deployment. The discussion below highlights examples of these shared challenges, as well as instances where developments in other countries may have valuable lessons for the United States.

The first insight is that policy (including mandates and targets) can be a useful initial driver for DERs, but ultimately growth in DERs should be sustained by well-functioned power markets and efficient retail tariffs. Policies ideally address specific barriers to DER deployment, including resource planning that explicitly considers DERs, DER-specific procurement targets, and retail rates that advance DERs. Legislation and regulation can help remove barriers to participation of DERs in power markets and facilitate DERs through more open and coordinated planning. In China, for example, *Electric Power Planning Administrative Measures* issued by the National Energy Administration (101) provides a useful blueprint for the power sector planning process in the country. However, planning guidelines do not incorporate demand-side resources into China's power sector planning processes, which should play a critical role in assessing cost-effective alternatives to conventional infrastructure, including NWAs, and coordinating generation and transmission investments and investments in demand-side resources.

In addition, coordination between national and local regulation may be needed to support DERs, requiring effective cooperation among regulatory agencies and between national and subnational governments. For example, devolving decision-making powers to local levels to serve as the default service provider or purchase and operate the distribution system has enabled municipal energy companies to actively promote DERs in Germany and Great Britain (102).

Second, it is important to reform existing utility regulatory models to shift the roles, responsibilities, and incentives of electric utilities away from building more traditional generation and grid infrastructure and incentivize them to extract value from existing assets to meet customer needs. European countries face a similar challenge because the recovery of capital expenditures is determined by the regulatory asset base under the existing cost recovery mechanism. The reduction of capital investment leads to a decrease in the asset base, which will directly affect the return on investment (97). Efforts to change utility incentives have been underway in some European countries for more than a decade and could provide valuable lessons for the United States and other countries. The United Kingdom's RIIO framework—Revenue = Incentives + Innovation + Outputs—which is a comprehensive performance-based regulatory system that motivates utilities to achieve desired results, is a prominent example of this (103). In addition, clarifying the roles and responsibilities of other market players such as an aggregator is essential to facilitate active participation of DER in the electricity system. Aggregators are also beginning to emerge as important intermediaries in other countries as well (104).

Third, tariff design is critical for balancing utility, consumer, and DER provider interests. Increasingly, tariffs will become more sophisticated, facilitating a more active and responsive distribution system and customer load. Retail tariff design, in areas such as NEM and time-based, dynamic prices, must effectively value DERs' contribution to power systems and create clear price signals to enhance customers' responsiveness to power system conditions. These issues are not unique to the United States. Studies focusing on NEM in India (105, 106) underscore the need for creating a more sustainable net metering policy that is economically viable for developing countries. A report on the integration of DER in the European Union points out that the value of flexibility is not always reflected in the market prices and that existing regulatory and institutional arrangements prevent the value of flexibility from being passed on to end customers (97).

Furthermore, tariff design needs to consider the rate impact of increasing DER deployment on customers that do not adopt DER. In Thailand, for example, increasing adoption of rooftop solar PV is estimated to have a significant financial impact on utilities and customers, leading to the loss of revenue for utilities and higher costs for nonsolar customers (107). Tariffs need to be carefully designed to avoid shifting costs from DER customers onto customers that do not adopt DER.

Fourth, allowing DER to participate in capacity markets, energy markets, and ancillary service markets has enabled DER to provide reliability and flexibility services. However, different conditions in different countries shape the extent to which DER values can be monetized through power markets. In Germany, for example, it is currently not practical to optimize the use of DER through an open market because no market participation model has been established for distributed system operators (108). In China, the newly released work plan for improving the market compensation mechanism for ancillary services (109) may offer new market opportunities for demand-side resources and energy storage in providing ancillary services. However, the construction of the country's power markets is still in its infancy, especially the spot market and ancillary service market, creating fewer opportunities for DER (110). In addition, in countries like China where overcapacity of power supply is significant (111), capacity values may be low. As China actively promotes electrification, especially in the industrial and transportation sectors, the situation may change (75).

Fifth, the proactive designs of DER interconnection policies and distribution open access rules are critical for increasing grid penetration of DERs. In countries such as China, however, there have been noticeable regulatory, policy, and technical barriers to grid interconnection of DER and distribution network access (112). The UK Open Networks Project is an example of national efforts to standardize processes and customer experiences in connecting DERs to the distribution networks that have valuable lessons for other countries (113).

DERs can play a significant role in supporting the development of future renewables-based power systems. Further studies are needed to continue examining the operational and economic impacts of DER at different penetration levels and on different layers of the power systems—generation, transmission, distribution, and end use. Better understanding the impacts of DER changes on the power system will help address potential future power system reliability challenges posed by high penetration of DERs on the grid.

SUMMARY POINTS

1. With the large-scale deployment of wind and solar generation on both the grid side and customer side, transmission system operators and distribution utilities face new operational challenges. These challenges include the need to balance a large amount of solar and wind energy output that is neither constant nor fully predictable and the need to more actively operate distribution systems that have growing penetrations of customer-sited resources.
2. DERs meet customers' growing interests in new, customer-sited applications such as distributed generation, energy storage, load response, and managing electric vehicles while providing flexible resources to enable dynamic load adjustments to real-time operational conditions, thus improving the stability of the grid and enhancing grid flexibility for integrating VRE.
3. In the United States, changes have been made at the federal level to regulate the wholesale power markets to promote the development of DER; at the state level, resource planning and procurement, retail price design, and public utility regulations

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are measures adopted to expand DER. In addition, the United States has also formulated market strategies and created new business models, including DER monetization through power markets, reform of utility business models, and DER aggregation to capture opportunities to increase DER deployment.

4. Mandates and targets can be a useful initial driver for DERs, but ultimately growth in DERs should be sustained by well-functioned power markets and efficient retail tariffs.
5. It is important to reform existing utility regulatory models to shift the roles, responsibilities, and incentives of electric utilities away from building more traditional generation and grid infrastructure and incentivize them to extract value from existing assets to meet customer needs.
6. Tariff design is critical for balancing utility, consumer, and DER provider interests. Retail tariff design, in areas such as NEM and time-based, dynamic prices, must effectively value DERs' contribution to power systems and create clear price signals to enhance customers' responsiveness to power system conditions. Tariff design also needs to consider the rate impact of increasing DER deployment on customers that do not adopt DER.
7. Allowing DERs to participate in power markets has enabled DERs to provide reliability and flexibility services. However, different conditions in different countries shape the extent to which DER value can be monetized through power markets.
8. The proactive designs of DER interconnection policies and distribution open access rules are critical for increasing grid penetration of DERs.

FUTURE ISSUES

1. What would be the operational and economic impacts of DER at different penetration levels and on different layers of the power systems—generation, transmission, distribution, and end use?
2. What open access rules are needed to allow distribution network operators to effectively dispatch DERs?
3. How to achieve an active management of DERs through distribution operations and better integration of DERs into regional markets and the bulk power system?
4. What tariff design changes should be made to balance utility cost recovery, the economic efficiency benefits of DERs, and sustainable growth in DER adoption?

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DISCLOSURE STATEMENT

The authors are not aware of any affiliations, memberships, funding, or financial holdings that might be perceived as affecting the objectivity of this review.

ACKNOWLEDGMENTS

The authors would like to thank the Energy Foundation for its support under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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IV. Management and Governance of Resources and Environment

V. Methods and Indicators