THE GROWTH OF DISTRIBUTED ENERGY

Implications for California

NEXT 10

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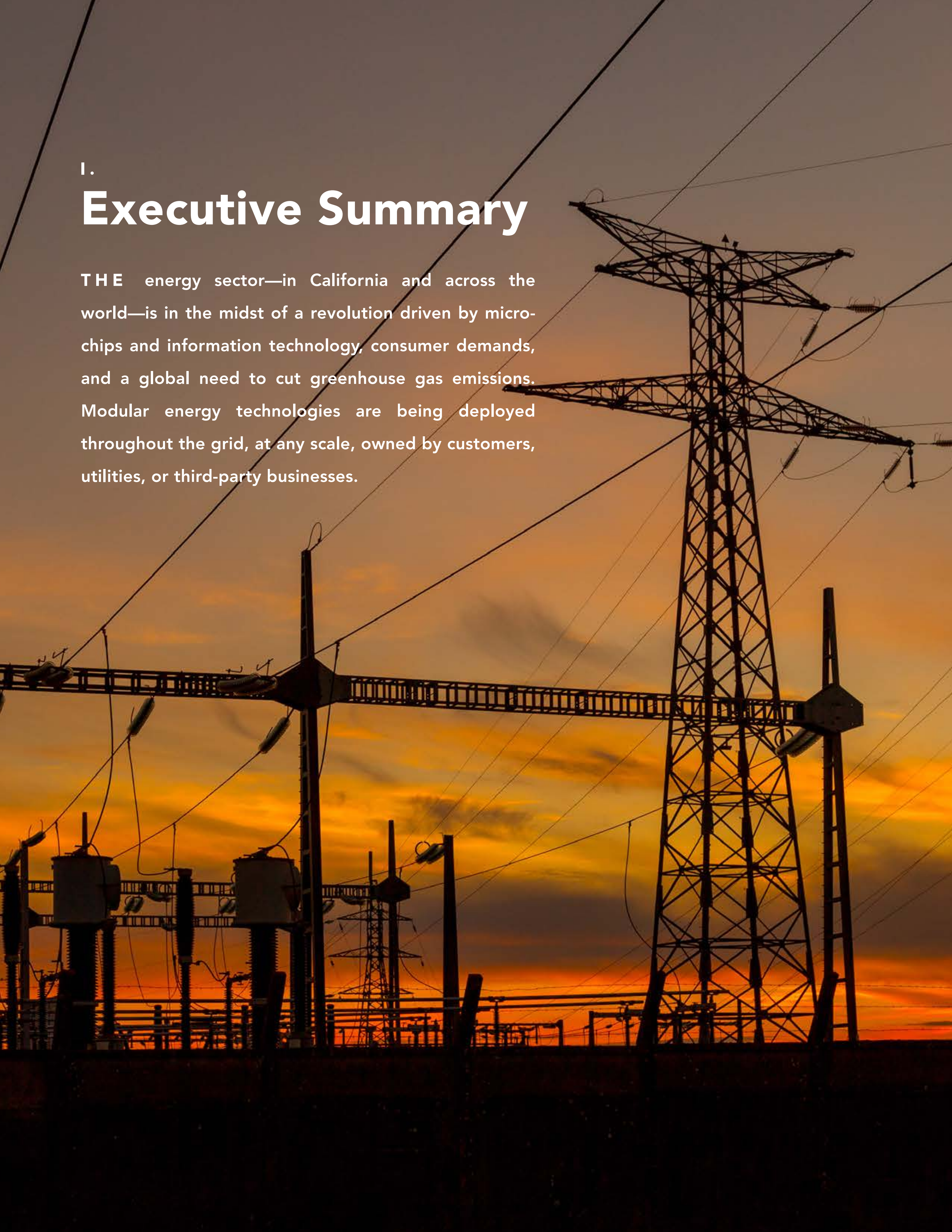
Next 10

JULY 2018

ACKNOWLEDGEMENTS

The author would like to thank Jon Wellinghoff of Grid Policy Inc., Matthew Tisdale of GridWorks, Colleen Kredell of Next10, Sage Welch of Cater Communications, and Brett Simon of GTM Research for their input. However, all errors are the responsibility of the author.



I.

Executive Summary

THE energy sector—in California and across the world—is in the midst of a revolution driven by microchips and information technology, consumer demands, and a global need to cut greenhouse gas emissions. Modular energy technologies are being deployed throughout the grid, at any scale, owned by customers, utilities, or third-party businesses.

Enabled by software and wireless communications, these distributed energy resources (DERs) are able to serve both end-use customers and grid managers, often at the same time. Consumers are merging with producers to become "prosumers," replacing the old paradigm of one-way buyer-seller transactions.

With an increasing amount of variable renewable energy sources being added to the California grid, the growth of DERs offers the potential to increase reliability and efficiency and to reduce costs and emissions. But DERs also raise a number of challenges.

WHAT ARE DERS?

Distributed energy resources compose a suite of diverse technologies that have one thing in common: they are modular replacements for traditional "central station" energy technologies.

This brief look at six categories of DERs:

1. **Distributed generation:** Small electric generators, including solar panels, wind turbines, fuel cells, gas turbines, and internal combustion engines that can be sited on the customer side of the meter or tucked into the distribution grid where they are most needed. California has seen significant growth in distributed solar generation, with a total of over 800,000 customers with rooftop solar systems, providing over 6,500 MW of capacity. The state has been adding 100,000 systems annually and in May 2018, the California Energy Commission added rooftop solar as a building code requirement, which could lead to an additional 75,000 installations per year.

2. **Demand response and targeted energy efficiency:** Controlling electricity demand is another way to bring supply and demand into balance. Energy efficiency measures can be targeted to deliver specific grid benefits. California is a world leader on energy efficiency, with investor-owned utilities spending more than $700 million on efficiency programs and measures per year. But more needs to be done to target energy efficiency investment toward integrating renewables and on demand response. Recent research suggests California could save an additional $750 million a year from more sophisticated demand response programs.

3. **Energy storage:** Energy can be stored as electricity, heat, ice, and other forms. This paper focuses on batteries, which are emerging rapidly for use in electric vehicles, but can also be used in stationary applications. Ninety percent of the nation's small-scale energy storage is in California, and almost half of the large-scale installations. But this will change soon: in June 2018, PG&E announced the world's largest battery project, to be installed near Monterey Bay in place of three natural gas power plants.

4. **Electric vehicles as grid tools:** When electric vehicles (EVs) are parked and plugged in, their batteries can serve as both demand response and energy storage. With California aiming for five million EVs on the road by 2030, there will be a huge opportunity to tap them for grid services. As EV batteries wear out they can live a "second life" as stationary batteries.

5. **Communication and control technologies:** Smart grid technologies enable better visibility and control into the transmission and distribution systems, as well as into customer's buildings and appliances. What can be seen and controlled can be used to save energy and money, and provide grid services. The biggest current trend in smart grid investment is to automate distribution system controls, with nearly $2 billion invested nationally last year, including nearly $250 million in California.

6. **Microgrids:** DERs can be bundled together, creating small grids within the big grid. Microgrids can improve reliability, save money and energy, help incorporate more renewables, and provide grid services. As of early 2017, there were 36 operating microgrids in California, with an additional 80 under construction or planned. Altogether the systems will have over 650 MW of peak capacity, less than one percent of the total in-state generation capacity, but an important resource to help manage grid reliability.

While DERs can work together, they can also compete with each other. Demand response and storage, for example, can both provide services to a utility or grid operator by reducing demand for generation at key times. Stationary batteries compete with batteries on wheels, in electric cars.

They also compete with large-scale generation, transmission and distribution lines, transformers and meters, and all the rest of the traditional "central station" infrastructure. At the same time, they can supplement and benefit from the traditional grid. While DER enthusiasts see a future with no transmission lines and big power plants, others see a hybrid approach that taps the best of both worlds.

CHALLENGES

The growth of distributed energy is creating many opportunities, but also many challenges. For example:

- It can be hard to do electric system planning since so many decisions are made by customers rather than planners, utilities, or regulators, and customer decisions can be hard to predict. While transmission and generation planning is a highly refined art after many years of experience, distribution system planning (DSP) is in its infancy.
- One difficulty with distribution system planning is that traditionally there has been little visibility into the distribution system. If DERs are going to be a distribution resource, there is a need for greater monitoring and communications to know what is happening at the distribution level, and new methods to place a value on DER deployment.
- For DERs to be deployed, their value must be monetized. Many DERs can create a stack of values that cut across different markets and jurisdictions, from the customer to the distribution grid to the wholesale market. DERs need access to these different levels in order to be monetized.
- The value of DERs can change with deployment. If storage is used to alleviate grid congestion in a pocket of the grid, then subsequent DERs in that area are worth less. The growth of solar is driving down the value of more solar, since the panels all produce power at the same time.
- DERs cause a shift in revenues away from traditional energy companies and technologies, who will fight to protect their market share. Utilities are promoting changes to rate designs across the country to counter the financial effect of DERs.
- Energy incumbents have an incentive to minimize the value of DERs to customers, as DERs compete with utility-owned investments. Yet incumbent utilities hold powerful sway over the regulatory process, with access to more information about the grid and their customers than any other parties involved in a regulatory proceeding. They can use this "information asymmetry" to win outcomes that suppress DERs in favor of utility solutions.

These challenges are being addressed in a multitude of utility commission and federal proceedings, legislation, and court cases, as well as in the marketplace, every day, by startups, tech giants, utilities, and customers.

RESPONSES

In this brief, the discussion of each category of DERs includes an overview of the technologies, a quick look at their deployment in the U.S. and in California, and a summary of California state policies.

Some policies affect all DERs, such as the design of retail electricity rates, interconnection rules, access to wholesale markets, and planning. Other policies are tailored to help specific technologies, such as mandates, procurement dockets, and valuation policies.

Because DERs are a diverse and growing set of technologies, with entrepreneurs developing new business cases every day, the policy landscape is also diverse and rapidly evolving. In the interest of readability and comprehension, this paper is nowhere near comprehensive. California alone currently has 15 dockets open at the state utility commission to deal with various aspects of DER deployment and regulation.

DERs have been the primary topic of discussion at industry conferences, at commission hearings, and in the trade press and academic literature for the past decade. They have been called a "disruptive challenge" and "restructuring 2.0," as momentous as the switch to competitive electricity markets that began in the 1990s.

Therefore, consider this paper a brief introduction to the growing world of distributed energy.

II.

Distributed Energy Resource Basics

DISTRIBUTED energy resources (DERs) are a collection of technologies that produce, store, manage, and reduce the use of energy. Their common theme is that they are small enough to be distributed on the grid, at or near customers, rather than centrally located like a big power plant.

FIG 1 Distributed Energy Resource Capabilities Matrix

Technologies	Energy	Generating Capacity	Distribution Capacity	Voltage Regulation	Frequency Regulation	Load Following	Balancing	Spinning Reserves	Non-Spinning Reserves	Blackstart
Distributed Solar	Energy Generator	◐	◐	●	●	●	●	No	No	No
Distributed Solar + Advanced Inverter Functionality	Energy Generator	◐	◐	◉	◉	◐	●	No	No	No
Battery Storage	Energy Storage	◉	◉	◉	◉	◉	◉	Yes	Yes	Yes
Interruptible Load	Load Shaping	◑	●	●	●	●	◉	Yes	Yes	No
Direct Load Control	Load Shaping	◑	◑	●	◑	◉	◉	Yes	Yes	No
Behavioral Load Shaping	Load Shaping	◐	◐	●	●	◐	◐	No	No	No
Energy Efficiency	Reduce Load	◑	◐	●	●	●	●	No	No	No

Source: Smart Electric Power Alliance[1]

● Unsuitable for reliably performing the specified service.

◑ Able to perform a service, but may be limited by factors such as avilability or customer behavior.

◐ May be able to perform a service, but is not well suited or can provide partial support.

◉ Well suited to perform a service; may exceed legacy technologies for providing the service.

DERs can be owned by utilities, grid operators, third parties, and customers. They can be sited on either side of the meter, providing services directly to a customer or to power companies. They can operate individually or be aggregated together to provide services to the grid, to customers, or both.

Many DERs come from the information technology revolution, using microchips, software, and communications to provide services that would have been impossible before.[1]

DERs offer a number of services at all levels of the grid. On the wholesale level, DERs can provide energy (MWh), generation capacity (MW), ancillary services, and transmission services. At the local level, DERs can provide services to distribution utilities as well as to customers, including energy, demand charge reduction, voltage and VAR support, and the deferral of investments in distribution infrastructure.

1 Smart Electric Power Alliance. "Beyond the Meter: Planning the Distributed Energy Future, Volume I: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources can be found at https://sepapower.org/resource/beyond-the-meter-planning-the-distributed-energy-future-volume-i/

WHAT COMBINED DERS CAN DO

MOORPARK

Coastal power plants that use ocean water for cooling are being affected by new rules from the California State Water Resources Control Board, and many are closing, including two plants on the coast of Santa Barbara and Ventura counties. To replace that capacity, two gas-fired power plants were proposed, the Puente Energy Center in Oxnard and the Mission Rock Energy Center in Ventura County. Opponents to the project, including the City of Oxnard, succeeded in getting regulators to do a thorough study of alternatives, including transmission lines and DERs such as battery storage. Ultimately CAISO decided to increase the capacity of a transmission line on existing towers, plus Southern California Edison will procure a mix of DERs and small gas plants.[2]

OAKLAND CLEAN ENERGY INITIATIVE

In West Oakland, a 40-year-old, 165 MW power plant that ran on jet fuel was becoming unable to support demand in the area, plus was a significant source of air pollution. In response, regulators took proposals on how to maintain reliability in the area without the plant. Proposals for a transmission line and a 40 MW and 160 MWh battery were rejected in favor of a package from PG&E that combines battery storage and demand response with line and equipment upgrades. The Oakland Clean Energy Initiative (OCEI) is seeking bids for up to 45 MW of DERs.[3]

2 Wendy Leung, "New power lines approved as aging Oxnard power plants ready for early exit," Ventura County Star, March 26, 2018, https://www.vcstar.com/story/news/2018/03/26/new-power-lines-approved-aging-oxnard-power-plants-ready-early-exit/454991002/

3 Darrell Proctor, "CAISO Backs PG&E Clean Energy Plan for Oakland," POWER Magazine, March 26, 2018, http://www.powermag.com/caiso-backs-pge-clean-energy-plan-for-oakland/

III.

California Policy Overview

CALIFORNIA has made a strong commitment to distributed energy resources, and has adopted virtually every policy ever thought of for DERs. In many areas—though not all—it is a leader in deployment as well.

DERs offer a number of opportunities for California.

- They can offer an alternative to new transmission lines, which are difficult to site, vulnerable to outages, and can pose fire risks.
- They represent a set of industries that have enormous global growth potential, many of which are growing out of the IT sector that is already so important to the state.
- They can help alleviate the environmental injustices of local pollution sources in disadvantaged communities, while creating local jobs and economic development.

But they have a number of potential risks and drawbacks as well.

- The cost of DERs can be higher than the traditional centralized grid. Centralized power plants, including renewables, enjoy economies of scale, while transmission lines can lower consumer costs by relieving congestion, facilitating competition, and connecting to lower cost resources. However, DERs can offer higher value to customers, partly because they compete with the higher retail cost of energy (rather than wholesale). Plus, their costs are rapidly declining.
- Greater use of IT-enabled DERs could endanger customer privacy and increase exposure to malicious software attacks, if cybersecurity measures are not sufficiently effective.
- DERs could lead to a lack of generation diversity, as solar is by far the dominant distributed generation resource.

DERs are being addressed by a suite of interlocking policies from the California Public Utilities Commission (CPUC), California Air Resources Board (ARB), the California Energy Commission (CEC), and the California Independent System Operator (CAISO). The CPUC's DER Action Plan from May 2017 lists 15 different regulatory proceedings, laws, and other policies.[4]

Possibly the most important single piece of policy is 2013's Assembly Bill 327. The law requires reform of utility distribution planning, investment, and operations to "minimize overall system cost and maximize ratepayer benefits from investments in preferred resources," while advancing time- and location-variant pricing and incentives to support distributed energy resources.

The CPUC organizes DER policies into three categories: rate design, distribution grid issues, and interaction with wholesale markets.

1. RATES AND TARIFFS

The Commission's vision for rates and tariffs is to provide options for all customer categories, to be technology neutral, and to reflect grid conditions and costs. For DERs, rates should be time and location dependent, they should promote energy efficiency and pollution reduction, and they should keep rates affordable for customers who don't use DERs.

In order for DERs to succeed, customers must be able to reap the benefits of their investments. The most fundamental way to do that is by rate design that encourages behaviors that can save money for both the customer and the power system as a whole. Rates can be designed to give accurate price signals to customers, and to incentive and monetize the use of DERs.

Commercial and industrial customers in California pay both energy charges and demand charges. With energy, customers pay for the number of kilowatt-hours they consume each month. Demand charges are based on the maximum amount of electricity used at one time over the course of a month. They are intended to reflect the amount of infrastructure needed to serve that customer: a customer with moments of high peak demand requires larger distribution equipment and bigger generation reserves.

One key issue is whether demand charges vary based on whether the customer's moment of peak demand happens during the system-wide peak (called "coincident peak"). One goal of a demand charge is to reduce the system's peak demand, since that requires greater

4 CPUC, California's Distributed Energy Resources Action Plan: Aligning Vision and Action, May 3, 2017, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/DER%20Action%20Plan%20(5-3-17)%20CLEAN.pdf

reserves to be available. If a customer's peak happens in the middle of the night, for example, it doesn't increase overall system demand.

Residential and small commercial customers usually don't pay demand charges, but they do typically pay a fixed charge each month to cover billing and other fixed expenses that are independent of the amount of their energy consumption. From a policy perspective, a large fixed charge can undermine energy efficiency and distributed generation policies, as well as have equity impacts on low-income and elderly households. Fixed charges are discussed in more detail in the section on distributed generation.

Rates can also vary with time, usually to discourage consumption during peak hours. Large peaks require more generators and more infrastructure, which imposes costs on all customers. The simplest way to communicate higher peak prices is through time-of-use (TOU) rates. TOU rates set peak and off-peak prices according to set time periods, which vary by season. Summer afternoons, for example, are on-peak periods and have the highest rates. Spring nights may have the lowest off-peak rates.[5]

More sophisticated customers, such as large commercial and industrial customers with energy managers on staff, can benefit from dynamic pricing. Under dynamic pricing (or time-varying rates), customers pay the real-time price of electricity on the wholesale market, which varies constantly. A sophisticated customer with flexible load or their own on-site generation can control their operations to minimize costs.[6]

California is adopting default TOU rates for all residential customers by 2019, as allowed by AB 327. TOU rates are currently required for commercial and industrial customers, but optional for residential customers. The change will make them mandatory for residential customers, with provisions for opting out in case of hardship.

2. DISTRIBUTION GRID INFRASTRUCTURE, PLANNING, INTERCONNECTION AND PROCUREMENT

The CPUC vision of success for this category is increased DER deployment and grid reliability with decreased cost, utilities that are motivated rather than resistant, and a technology-neutral and competitive procurement process.

States have long used integrated resource planning (IRP) to study future needs. The "integrated" part of IRP is to include both supply and demand options, such as comparing investments in energy efficiency against new power plants. The same concept is being extended to distribution systems, comparing new infrastructure investments against DERs.

There are a number of proceedings underway in California and in other states on the opportunity for DERs, grid modernization, and a planning and procurement framework. A key task has been to develop standard methods and tools to characterize the distribution grid, like identifying where it is weak, how DERs could replace traditional grid investments, and the dollar value of deploying DERs in a given location.

The IRP equivalent is the Distribution Resource Plan (DRP). The three large investor-owned utilities (IOUs) in California developed DRPs in 2015 and are undertaking pilot projects that use DERs to defer or replace grid upgrades. There are further technical working groups underway on grid planning, DER valuation, and DER growth scenarios.

The interconnection process for new distributed generation has had to work through a number of issues. Utilities approve the technical aspects of connecting new generation to the grid; officials set codes and standards for electrical safety; and local governments issue construction permits. The growth of distributed solar has helped resolve issues in all of these areas, and reduced the burden and delay in connecting new

5 For more on rate design see Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project, Smart Rate Design for a Smart Future, 2015, http://www.raponline.org/document/download/id/7680

6 Advanced Energy Economy, Rate Design for a DER Future: Designing Rates to Better Integrate and Value Distributed Energy Resources, January 22, 2018, https://info.aee.net/hubfs/PDF/Rate-Design.pdf

systems. These improvements have helped reduce the "soft costs" of deployment—all the costs other than the hardware—driving down costs to consumers.

3. WHOLESALE DER MARKET INTEGRATION AND INTERCONNECTION

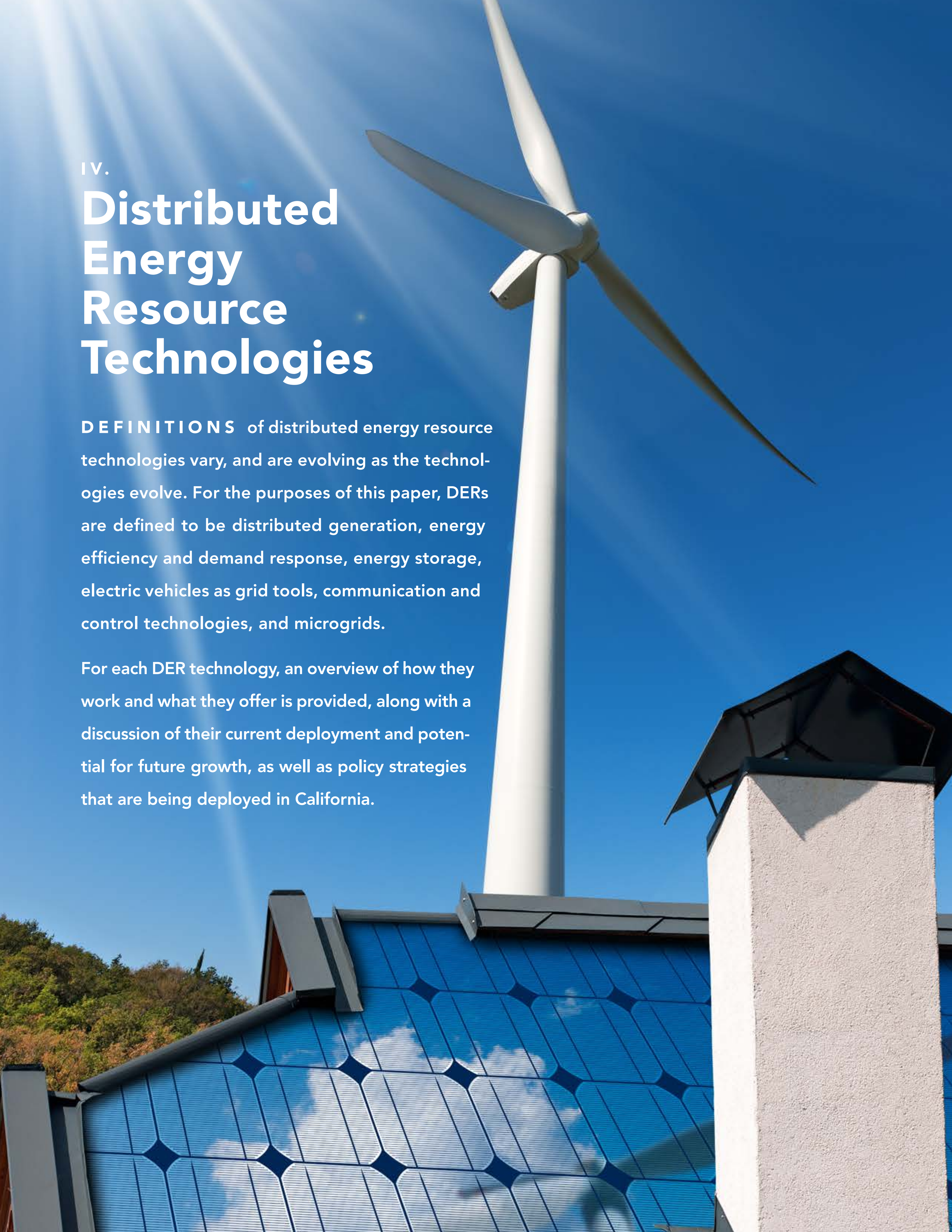
Even though DERs are typically installed at the distribution level, they can affect operations at the wholesale level. This interplay is complicated by a split jurisdiction, as the distribution grid is operated by utilities and regulated by state utility commissions while the transmission grid is operated by regional transmission operators (RTOs) and regulated by the Federal Energy Regulatory Commission (FERC). Moreover, the transmission grid in areas where there are RTOs is operated by independent non-profit entities, while the distribution grid is generally run by monopoly distribution utilities. There is a patchwork of competitive and monopoly markets at the retail and wholesale levels. DERs offer a new form of competition in areas still operating as regulated monopolies.

Because DERs can provide value to the wholesale market, the distribution grid, and to end-users, they can "stack" the value of their services to bring in more revenues – but only if they have access to all levels.

Traditionally all wholesale power supply was centralized. Now DERs can be integrated into the wholesale market, increasing competition for energy, capacity, and ancillary services. But DERs can't participate in wholesale markets unless they are visible and communicating with market operators. DERs must have RTO-grade equipment that can communicate with CAISO, which is often cost prohibitive for very small distributed resources. One solution is to allow aggregators to bundle together customers with DERs and offer their services as a group into wholesale markets.

CAISO is currently convening the Energy Storage and Distributed Energy Resources (ESDER) initiative to "lower barriers and enhance the abilities for energy storage and distribution-connected resources to participate in the CAISO markets."[7] This will include linking DERs to CAISO's Energy Imbalance Market, which offers utilities around the West a way to balance short-term needs. (For more information on regional issues, see the companion Next10 report, A Regional Power Market for the West.)

7 CAISO, Energy Storage and Distributed Energy Resources, accessed May 2018, http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx



IV.

Distributed Energy Resource Technologies

DEFINITIONS of distributed energy resource technologies vary, and are evolving as the technologies evolve. For the purposes of this paper, DERs are defined to be distributed generation, energy efficiency and demand response, energy storage, electric vehicles as grid tools, communication and control technologies, and microgrids.

For each DER technology, an overview of how they work and what they offer is provided, along with a discussion of their current deployment and potential for future growth, as well as policy strategies that are being deployed in California.

Distributed Generation

i. TECHNOLOGY BASICS

Distributed generation (DG) includes a variety of small generators, including wind turbines, fuel cells, and microturbines, but it is dominated by solar power.

The size limit for a distributed generator varies by the policy, but they are often less than two megawatts (MW). By far the most common and numerous DG technology is the solar photovoltaic panel. A single panel might produce 150 to 300 watts at full sunlight, and they can be deployed in any scale, from a single panel on a streetlight to over nine million panels at the Topaz solar farm in San Luis Obispo County. The dividing line between transmission and distribution systems is typically the substation. Anything on the distribution side of the substation is considered a distributed resource.

Inverters convert the DC power coming from a solar panel to AC power for use in homes and on the grid. Inverters are becoming a DER in their own right, thanks to software controls and communications that can deliver a variety of capabilities. A "smart inverter" can remain connected to the grid under a wider range of voltage and frequency levels, rather than suddenly tripping offline if there is a disturbance. They can also help counteract voltage deviations on the grid, providing greater power quality and reliability. With the right communication capabilities, grid operators can collect data, monitor, and remotely adjust the operation of inverters to support the grid.[8]

Other DG technologies include internal combustion engine generators, small combustion "micro-turbines," fuel cells, and wind turbines. Combustion generators are often configured in a "cogeneration" system that produces heating, cooling, and electricity for buildings, campuses, or factories. Fuel cells are a non-combustion technology that converts hydrogen to electricity; most often the hydrogen is derived from natural gas, but it can also be produced from water using electrolysis or from biogas, which is derived from landfill gas, manure, and other biogenic sources.

ii. CURRENT AND POTENTIAL DEPLOYMENT IN CALIFORNIA

California currently has over 800,000 customers with rooftop solar systems, totaling over 6500 MW of capacity. The state has been adding 100,000 systems annually in recent years.[9] In May 2018, the California Energy Commission added rooftop solar as a building code requirement, which could lead to an additional 75,000 installations per year, depending on home-building trends.[10]

Cogeneration systems are growing as well, with 1,220 systems installed in factories, campuses, and large commercial buildings, adding up to 8,590 megawatts of capacity.[11] Systems of over 20 MW account for 83 percent of capacity, and natural gas accounts for 85 percent of the fuel supply. The oil and gas extraction sector constitutes the largest amount of capacity (2448 MW), followed by food processing and refineries. Most big cogeneration systems use gas and steam turbines while smaller systems are dominated by 716 reciprocating engine generators, plus 188 microturbines and 82 fuel cells. The U.S. Department of Energy (DOE) sees the potential for another 11.5 gigawatts of cogeneration in California, in a variety of industries and system sizes.

As of March 2018, more than 220 MW of fuel cell systems were installed in close to 200 cities in California. Fuel cell prices have fallen by 70 percent in the past decade, according to the California Stationary Fuel Cell Collaborative.[12]

8 Aurora Solar, "California's New Smart Inverter Requirements: What "Rule 21" Means for Solar Design," November 8, 2017, http://blog.aurorasolar.com/californias-new-smart-inverter-requirements-what-rule-21-means-for-solar-design

9 California DG Statistics, accessed April 2018, https://www.californiadgstats.ca.gov/charts/.

10 Christian Roselund, PV Magazine, "California's solar mandate: Questions and answers," May 10, 2018, https://pv-magazine-usa.com/2018/05/10/californias-solar-mandate-questions-and-answers/

11 US Department of Energy, The State of CHP: California, accessed June 2018, https://www.energy.gov/sites/prod/files/2017/11/f39/StateOfCHP-California.pdf

12 California Stationary Fuel Cell Collaborative, accessed June 2018, http://www.casfcc.org/Map_Of_CA_Fuel_Cell_Installations.html

There are an estimated 15,000 stationary backup generators (BUGs) in California, which run mostly on diesel fuel. Because of their high emissions, air regulations restrict their use to a certain number of hours per year, which limits their ability to supply grid power. (Emergency use is not limited.) If they have the proper pollution controls, BUGs can be used in conjunction with demand response programs in many parts of the country. But as of January 2018, California rules prohibit their use in demand response programs.[14]

There are very few distributed wind turbines in California. Small turbines, such as 10 kW or less, are used in rural areas in net metering applications. A handful of utility-scale turbines have been deployed individually to supply large customers. California had a total of 66 MW of distributed wind turbines in 2016, primarily from turbines larger than one megawatt, ranking fifth among states.[15]

Apple's New Headquarters in Cupertino - Solar Panels

The new Apple "spaceship" headquarters in Cupertino is now the largest LEED Platinum-certified office building in North America and has the world's largest rooftop solar system. It is powered by 100 percent renewable energy from multiple sources, including a 17-megawatt rooftop solar installation and four megawatts of biogas fuel cells, and controlled by a microgrid with battery storage[13]

iii. POLICIES

The most fundamental policies for DG are interconnection and net metering.

Interconnection involves getting permissions from the distribution utility and the local government, and meeting electrical safety codes. Utility, state, and local officials have worked hard to streamline the interconnection process as a way to reduce the "soft costs" of solar deployment—all of the costs other than hardware. California's "Rule 21" process has set standards for interconnection since 1982, most recently covering energy storage systems and a shift to "smart inverters" that enable better integration of solar with grid functions.[16]

Net metering has been a contentious issue in the United States. Net metering is an accounting technique that tracks the production of customer-owned solar power. Old analog meters with spinning dials couldn't tell when or how power was consumed; they only counted total kilowatt-hours flowing through the meter. For customers with solar panels, the power could flow back through the meter onto the grid at times, making the meter literally spin backward. At the end of the month the utility read the meter to find the net consumption. As a result, customer-generated power was simply subtracted from the bill, giving it full retail value.

Now digital meters can keep track of when and how much solar power is generated. Utilities have argued that if solar customers don't pay for the upkeep of the grid, the costs will be borne by customers who don't go solar. This will raise their costs, thus encouraging

13 Apple. Photo from: https://www.apple.com/newsroom/2018/04/apple-now-globally-powered-by-100-percent-renewable-energy/

14 California PUC, Decision Adopting Guidance for Future Demand Response Portfolios And Modifying Decision 14-12-024, Decision 16-09-056, September 29, 2016, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K725/167725665.PDF

15 US Department of Energy, 2016 Distributed Wind Market Report, https://www.energy.gov/eere/wind/downloads/2016-distributed-wind-market-report

16 CPUC, Rule 21 Interconnection, accessed May 2018, http://www.cpuc.ca.gov/Rule21/

them to go solar too—creating a financial death spiral that would undermine grid reliability, according to utilities. Customers that can't afford to go solar will be stuck with ever-increasing costs, they say. Proponents counter that distributed solar creates benefits to the grid and to society that outweigh the costs, including pollution reduction, increasing household prosperity and ownership, and creating local jobs.

Utilities have argued that residential customers should pay a greater portion of their bill in fixed charges, to make up for the loss of revenues utilities get from selling kilowatt-hours. While a standard fixed charge may be $10 per month, utilities have proposed raising it to as much as $80 a month, while lowering the cost of each kilowatt-hour. This would have the effect of encouraging more consumption, and discouraging energy efficiency and distributed generation.

Last year, regulators in 35 states made 84 changes to fixed charge and minimum billing policies.[17] Altogether, regulators made 249 changes to solar DG policies in 45 states, many of which have eroded the economics of solar DG.

Many states have rejected higher fixed charges, since they undermine clean energy goals and have disproportionate impacts on low-income and elderly customers. Instead, some states have moved to accounting systems that separate the cost components of utility service and attribute a specific (usually lower) value to customer-owned solar generation. California regulators adopted "net metering 2.0" in 2016, which shifted some costs to solar customers, but largely maintained the previous system.[18]

An alternative to net metering is the feed-in tariff (FIT), where customer-owned generation is sold to the utility at a fixed price, and the customer buys all of their power from the utility. FITs are the most common policy for DG in other countries, but are much less common in the US.

California has used FITs in the past. The Renewable Auction Mechanism (RAM) and the Renewable Market Adjusting Tariff (ReMAT) were both intended to procure distributed renewables projects using a feed-in tariff with prices set by bidding or by an automatic price decline. Neither program is having their intended effect.[19]

The RAM was "designed to facilitate quick, simple transactions where projects can come online relatively sooner," according to the CPUC. FIT prices were determined in a reverse auction, and winners were awarded a standard, non-negotiable contract and required to be online within 36 months. Utilities held six RAM auctions between 2011 and 2014, awarding contracts to 1,388 MW of projects in the 3-20 MW size range. In 2015 the CPUC changed the program to allow utilities to offer RAM procurement auctions at their own discretion.[20]

Utilities now use the RAM process to procure renewables for their Green Tariff Shared Renewables (GTSR) program, which allows customers to source their power from off-site generators.[21] However, customer demand for the Shared Renewables program has been weak, resulting in little procurement of DG under this program.[22]

17 North Carolina Clean Energy Technology Center, The 50 States of Solar: 2017 Policy Review and Q4 2017 Quarterly Report, January 2018, https://nccleantech.ncsu.edu/wp-content/uploads/Q4-17_SolarExecSummary_Final.pdf

18 Energy Sage, "California Net Metering: Everything You Need to Know About NEM 2.0," https://news.energysage.com/net-metering-2-0-in-california-everything-you-need-to-know/

19 Chris Warren, "California's Wholesale Distributed Solar Program Is in Trouble. Will Regulators Finally Fix It?", Greentech Media, June 16, 2017. https://www.greentechmedia.com/articles/read/california-wholesale-distributed-solar-program-is-in-trouble#gs.r0PCA68

20 CPUC, Renewable Auction Mechanism Program, accessed May 2018, http://www.cpuc.ca.gov/Renewable_Auction_Mechanism/

21 CPUC, Green Tariff/Shared Renewables Program (GTSR), accessed May 2018, http://www.cpuc.ca.gov/General.aspx?id=12181

22 Karin Corfee, John Powers, and Andrea Romano, "Community Solar: California's Shared Renewables at a Crossroads," Renewable Energy World, October 2, 2017 https://www.renewableenergyworld.com/articles/2017/10/community-solar-california-s-shared-renewables-at-a-crossroads.html

Moreover, in October 2016 San Diego Gas & Electric requested to end further procurement obligations under the RAM program, saying they were ahead of the renewable energy targets under the RPS program and can meet future targets without incurring additional RAM costs. A CPUC judge denied the request last August, but the full Commission has not yet ruled on the matter.[23]

A subsequent program, ReMAT, required a total of 750 MW of capacity statewide, including 500 MW allocated to California's three large investor-owned utilities. However, a federal District Court ruling in December of 2017 declared that the Re-MAT program conflicted with the federal Public Utilities Regulatory Policy Act (PURPA) of 1978, which regulates utility obligations to purchase power from qualifying facilities at the utility's "avoided cost." ReMAT, they ruled, establishes a purchase price different than the utility's avoided cost.[24]

Community choice aggregators have begun to revive the feed-in tariff.[25] MCE Clean Energy, serving communities in Marin, Napa, and Contra Costa counties, offers a FIT for projects under one megawatt and between one and five megawatts. MCE offers a 20-year contract at a fixed price, with the price for new contracts stepping down $5 per MWh in two and five megawatt increments.[26]

Targeted Energy Efficiency and Demand Response

i. TECHNOLOGY BASICS

Electricity demand (also called load), can be managed to provide savings to customers and services to the grid. Energy efficiency measures, like better pumps and motors, can reduce demand in general, or at certain times and places. Efficient lighting, for example, can reduce evening loads. Some load is flexible, and can be turned up and down as needed to save money or provide grid services.

Energy efficiency is encouraged by governments and utilities at the federal level and in all 50 states through tax incentives, rebates, appliance standards, building codes, and active programs such as energy audits and training. While all of these approaches save energy, money, and pollution, some energy efficiency measures are more strategic, targeted toward specific grid outcomes, making them more like other DERs. Efficiency targeted at certain areas on a grid can reduce the need for transmission or distribution system upgrades, as a "non-wires" alternative. Measures that deliver savings at certain times of day or seasons can reduce the need for generation to meet peak demand. Air conditioners are especially culpable for causing periods of peak demand—and very high price spikes—so targeting more efficient air conditioners, building insulation, and low-emissivity windows can cut costs and improve reliability on the grid.

23 Anne Simon, Administrative Law Judge, CPUC, "Revised Decision Denying San Diego Gas & Electric Company's Petition for Modification of Decisions (D.) 10-12-048, D.12-02-002, and D.14-11-042 To Terminate Its Renewable Auction Mechanism Procurement Requirements," August 22, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M193/K982/193982841.PDF

24 "Winding Creek Solar LLC v. Peevey," United States District Court Northern District of California, December 5, 2017, Case No. 13-cv-04934-JD (N.D. Cal. Dec. 6, 2017), https://casetext.com/case/winding-creek-solar-llc-v-peevey-2

25 For more information on community choice aggregators and their DG offerings, see the companion Next 10 brief, "The Growth of Community Choice Aggregation: Impacts to California's Grid," available at https://www.next10.org/grid-cca

26 MCE Clean Energy, Feed-in Tariff, accessed May 2018, https://www.mcecleanenergy.org/feed-in-tariff/

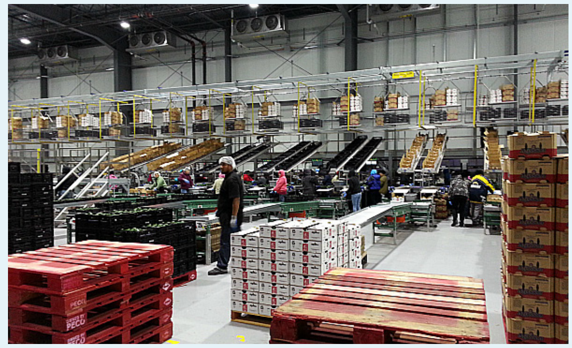
In California a key concern is the impact of large amounts of solar generation during the day, which can lead to large ramps in the evening as demand rises and solar output declines. This "duck curve," so-called because the daily load curve resembles the profile of a swimming duck, can be addressed in part by targeting energy use in the evenings. Residential lighting, air conditioning, and streetlights are especially promising targets.[27]

A related strategy is known as "demand response" or DR. A customer's electricity use can be controlled by a grid operator, a utility, a third party, the customer, or a software program. Most commonly, load is cut during periods of high power prices, such as by turning air conditioners down or off, or dimming lights. Formerly known as "direct load control," utilities have long used it to cut demand from air conditioners when supplies were tight. Now with more sophisticated controls and communication, demand response can provide a variety of services. A recent report by the Lawrence Berkeley National Laboratory (Berkeley Lab) and others dubbed these DR services "shape, shift, shed, and shimmy."[28]

Shape is DR that reshapes customer load profiles by responding to prices or behavioral campaigns, with advance notice of months to days.

- Shift is DR that encourages moving energy consumption from one period to another, such as to when there is a surplus of renewable generation. Shift could smooth the ups and downs caused by daily patterns of solar energy generation.
- Shed describes loads that can be curtailed to cut peak demand and support the system in emergency events—at the statewide level, in local areas of high load, and on the distribution system. This is the traditional form of DR.
- Shimmy involves using loads to dynamically adjust demand for short time periods to alleviate short-run variations and disturbances.

Mission Produce in Oxnard, CA



Mission Produce (https://www.worldsfinestavocados.com/) in Oxnard, California[29]

Mission Produce, a company in Oxnard that packs, markets, and delivers avocados, saves money by participating in Southern California Edison's demand response programs. Their packing and distribution facilities – the largest in North America – use energy efficient LED lighting, batteries, and over four acres of rooftop solar panels that provide three-quarters of their power during peak season. They use software that monitors and controls energy use at all of their facilities, and enables automated responses to load reduction events, enabling them to save about $25,000 per year. The software controls energy for cold storage equipment such as compressors, evaporators, condensers, and hydrocoolers, as well as for battery chargers, ripening rooms, and some lighting.

To be valued, the services provided by demand response need be monetized. Historically, the most valuable services have been in providing capacity or cutting load during periods of peak demand, and in reducing bills for customers on time-sensitive rates. DR programs can be offered by both retail utilities and in wholesale markets.[29]

27 Jim Lazar, Regulatory Assistance Project, *Teaching the "Duck" to Fly, Second Edition*, 2016, http://www.raponline.org/document/download/id/7956, and Sierra Martinez and Dylan Sullivan, Natural Resources Defense Council, "Using Energy Efficiency To Meet Flexible Resource Needs and Integrate High Levels of Renewables Into the Grid," 2014 ACEEE Summer Study on Energy Efficiency in Buildings, https://aceee.org/files/proceedings/2014/data/papers/5-1012.pdf.

28 Lawrence Berkeley National Laboratory, *Charting California's Demand Response Future: 2025 California Demand Response Potential Study: Final Report on Phase 2 Results*, March 1, 2017, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698

29 Mission Produce. Photo from: https://mamalikestocook.com/mission-produce-packing-house-tour-oxnard-california/

TABLE 1 Demand Resource Participation in US ISO and RTO Demand Response Programs

	2015		2016	
	Demand resources (MW)	Percent of peak demand	Demand resources (MW)	Percent of peak demand
California ISO	2,160	4.4%	1,997	4.3%
ERCOT	2,100	3.0%	2,253	2.9%
ISO-New England	2,696	11.0%	2,599	10.2%
MidContinent ISO	10,563	8.8%	10,721	8.9%
New York ISO	1,325	4.3%	1,267	3.9%
PJM Interconnect	12,866	9.0%	9,836	6.5%
Southwest Power Pool	0	0.0%	0	0.0%
TOTAL	**31,710**	**6.6%**	**28,673**	**5.7%**

Source: FERC[30]

Valuing DR in wholesale markets has been a contentious process. FERC strongly supported DR by issuing Order 745 in 2011, which required regional transmission operators (RTOs) to compensate demand response on an equal basis with generation resources in energy markets.[31] RTOs that also procure future generation capacity, such as in the PJM, New York, and New England ISOs, also allow DR aggregators to participate in those auctions. In 2013 alone, DR delivered $12 billion in customer savings in the PJM Interconnect.[32] Opposition from generation owners led to a series of court challenges that ended with a Supreme Court decision in 2016 that upheld the FERC order on demand response in energy markets.[33]

However, demand response was dealt a setback in the capacity market in PJM by changes in wholesale market rules there that made some forms of DR ineligible. According to FERC data, DR participation fell from nine percent of peak in PJM in 2015 to only 6.5 percent the following year.[34] Nationally, it fell from 6.6 to 5.7 percent of peak demand in the seven organized wholesale markets that FERC tracks. But in PJM's most recent auction for capacity in the years 2021-22, DR rose to 11,886 MW, an increase of 20 percent from the previous year.[35]

Retail demand response programs, operated by individual utilities, grew between 2014 and 2015 by 1,684 MW, or 5.4 percent, to 32,875 MW nationally. Over half of the capacity comes from interruptible load in the industrial sector.

30 FERC. Demand Response and Advanced Metering Assessment can be found at: https://www.ferc.gov/legal/staff-reports/2017/DR-AM-Report2017.pdf

31 Federal Energy Regulatory Commission, *Demand Response Compensation in Organized Wholesale Energy Markets*, 18 CFR Part 35 [Docket No. RM10-17-000; Order No. 745], issued March 15, 2011, https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

32 Bentham Paulos, "FERC Order 745 and the Epic Battle Between Electricity Supply and Demand," POWER Magazine, December 12, 2014, http://www.powermag.com/ferc-order-745-and-the-epic-battle-between-electricity-supply-and-demand/

33 Robert Walton, "What the Supreme Court decision on FERC Order 745 means for demand response and DERs," *Utility Dive*, February 3, 2016, https://www.utilitydive.com/news/what-the-supreme-court-decision-on-ferc-order-745-means-for-demand-response/413092/

34 Federal Energy Regulatory Commission, *2017 Assessment of Demand Response and Advanced Metering, Staff Report*, December 2017, https://www.ferc.gov/legal/staff-reports/2017/DR-AM-Report2017.pdf

35 PJM Interconnect, *2021/2022 RPM Base Residual Auction Results*, May 23, 2018, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en

ii. CURRENT AND POTENTIAL DEPLOYMENT IN CALIFORNIA

Although California is a national and even global leader in most clean energy and climate policies and technologies, it has lagged on deployment of demand response. As shown in Table 1, only 2,000 MW of controllable demand was enrolled in CAISO DR programs in 2016, less than 4.5 percent of peak demand, substantially less than other organized markets. Most of this demand is in traditional curtailment (or Shed) resources.

Much of the current DR resource comes from the Base Interruptible Program (BIP), which pays commercial and industrial customers to be ready for curtailment events. California utilities have maintained about 900 MW of load enrolled in the program, which cost $98 million in 2013.[36] BIP has accounted for over half of all capacity enrolled in DR programs and about one-third of all DR program costs. Only seven events were called between 2005 and 2013, largely to avoid system overloads.

A state Senate research report in 2014 concluded that utilities and CAISO were not using DR programs as a resource to meet real-time grid needs, except as a last resort. "California utilities spend significant amounts of ratepayer funds on the state's demand response programs, yet the benefits to ratepayers are unclear," the study concluded.[37]

The study found a number of policies and programs that were expensive and ineffective, or that had a large amount of free ridership. In one case, Southern California Edison paid customers a "peak-time rebate" for cutting use during periods of high demand, but later found that "95 percent of all incentives were paid to customers who either were not expected to or did not reduce load significantly."

Due to these shortcomings, and the potential to do much more demand response, the CPUC undertook a reform of DR policies in 2016, as discussed in the policies section below.

The Berkeley Lab study previously cited found substantial potential for growth in DR in California, as well as a need to change direction.[38] The growth of wind and solar power and slow retirement of existing gas power plants means there is plenty of generation capacity, making Shed DR for the system as a whole much less important. The report says "there is close to zero value created related to avoiding investment in the generation fleet" from load shedding as it's done today. They suggest shifting focus to local and distribution system needs and portfolios of resources that combine "targeted fast Shed" with Shift resources.

Shift resources make up the largest potential resource, according to the Berkeley Lab, especially if they are sited in the distribution grid to relieve congestion. The report estimates Shift DR could move up to 25 GWh per day (out of a total of about 600 GWh per day of demand) with a total value of $700 million per year. The largest of these resources are big industrial loads, agricultural water pumps, and commercial air conditioning.

Shape DR resources could amount to 1 GW of demand during peak hours by 2025 while Shimmy services could provide 600 MW of high-value load following and regulation services, worth about $43 million per year.

Commercial and industrial customers are required to be on time-of-use rates, and can opt-in to critical peak pricing (CPP) rates. With CPP, a utility can call a limited number of events each year that trigger very high electricity prices for a few hours. Customers that cut demand both save money during those hours and earn credits for later bill reductions.[39]

36 Michael W. Jarred, California Senate Office of Research, Delivering on the Promise of California's Demand Response Programs, *Policy Matters*, June 2014, http://sor.senate.ca.gov/sites/sor.senate.ca.gov/files/Delivering%20on%20the%20Promise%20of%20Californias%20Demand%20Response%20Programs.pdf

37 Jarred, ibid.

38 Berkeley Lab, ibid., and Jeff St. John, Greentech Media, "How California Can Shape, Shift and Shimmy to Demand Response Nirvana," January 26, 2017, https://www.greentechmedia.com/articles/read/how-california-can-shape-shift-and-shimmy-to-demand-response#gs.Zb4kyi0

39 Southern California Edison, "Demand Response Programs," accessed July 2018, http://tinyurl.com/y96ctwgb

The adoption of default time-of-use rates for residential customers in 2019 could significantly increase participation in DR programs in homes. But the authors warn that DR will compete with other distributed energy resources, including behind-the-meter storage, electric vehicles, new automation technology (known as the "Internet of Things"), and monetized distribution system service.

iii. POLICIES

California has a comprehensive suite of energy efficiency programs, honed over the past fifty years, including ratepayer-funded utility programs, appliance standards, and building codes.[40]

These programs are intended to reduce energy demand, create customer savings, reduce the need for investment and infrastructure, and cut pollution. In the traditional world of fossil and nuclear generation, the highest value for energy efficiency was to cut peak demand, thus avoiding the need for peaking power plants, cutting reserve margins, and reducing transmission and distribution capacity. Thus, a priority was put on energy efficiency programs that cut peak demand, relative to other benefits of energy efficiency.

Recently, as renewable energy has become a critical part of statewide energy supply, the economics of energy efficiency valuation have evolved. Energy saved from natural gas or imported fossil generation is more valuable than energy saved from renewable resources due to the low operating costs of wind and solar energy farms. Moreover, energy efficiency programs have included a carbon planning price (in addition to the carbon cap and trade allowance price) in the cost-benefit calculations used to design programs, thus putting an even greater emphasis on time periods when natural gas or imported fossil generation is on the margin. Still, no "targeted energy efficiency" programs have been developed specifically to help integrate solar and wind power, as described earlier.

Under the statewide integrated resource plan (IRP) proceeding, efforts are underway to optimize efficiency programs to meet the state's 2030 greenhouse gas (GHG) reduction targets in the most cost-efficient manner. This could further favor those energy efficiency measures that reduce GHGs and are complementary to renewables.[41]

In response to the poor performance of demand response programs mentioned in the previous section, the CPUC initiated a policy reform in 2016.

The new approach seeks to replace the utility-program approach with a goal that "Demand response shall be market-driven leading to a competitive, technology-neutral open market in California with a preference for services provided by third parties through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions."[42]

- The Demand Response Auction Mechanism (DRAM) is a pilot program by the state's three IOUs to procure DR resources of 100 kW or more from third-party aggregators. The annual solicitation provides a payment for controllable capacity (MW). DRAM has procured 40, 80 and 200 MW of load in its first three years, with a budget of $27 million in the most recent round.[43]
- CAISO has worked to allow distributed DR to participate in wholesale markets, providing energy and ancillary services to the CAISO market. The Proxy Demand Response (PDR) program is a CAISO market for load to participate in day ahead and real-time markets based on financial savings, while the Reliability Demand Response Resource (RDRR) program is for DR for reliability purposes.
- Utilities continue to offer their own DR programs, such as the BIP, air conditioner controls, and the Agriculture and Pumping Interruptible Program.
- CAISO puts out calls for conservation through the FlexAlert program, a form of voluntary, manual DR. Customers are notified by social media, and are not compensated for responding.

40 For more information on California energy efficiency policies, see the Next10 report, "Transforming the Grid."

41 Mohit Chhabra, Natural Resources Defense Council, personal communication, July 13, 2018. Also, California Public Utilities Commission, Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP), accessed July 2018, http://www.cpuc.ca.gov/irp/

42 Jeff St. John, Greentech Media, "Sweeping Changes Proposed for Demand Response in California," September 7, 2016, https://www.greentechmedia.com/articles/read/big-changes-proposed-for-demand-response-in-california#gs.0fuEruw

43 Jeff St. John, Greentech Media, "California's DRAM Tops 200MW, as Utilities Pick Winners for Distributed Energy as Grid Resources," July 26, 2017, https://www.greentechmedia.com/articles/read/californias-dram-tops-200mw-as-utilities-pick-winners-for-distributed-energ#gs.NaosQco.

The CPUC has also supported efforts to integrate demand response and other DER programs. The integrated demand-side management (IDSM) program, launched in 2007, brings together DR and energy efficiency programs through a series of activities, pilots, and programs with a current budget of about $8 million per year. IDSM is intended to provide "a smoother decision-making process for customers" through "marketing and delivery of the right combinations of programs and messaging at the right time to the right customer." It was recently extended with a focus on residential HVAC controls, and non-residential HVAC and lighting controls.[44]

The California Energy Commission has also played an important role by funding over $22 million in DR research. More than half has gone to the Demand Response Research Center at Berkeley Lab, which, among other things, developed a communication infrastructure called Open Automated Demand Response (OpenADR), which is now the global standard protocol for aggregators, utilities, and energy users to send signals about energy use and management.[45]

Energy Storage

i. TECHNOLOGY BASICS

Distributed energy storage has been available for many years, but is emerging now as a commercially viable technology. Batteries (a form of chemical storage) are falling rapidly in price, as production for electric vehicles scales up. Batteries can be installed as stationary units in any number, from single batteries in homes to hundreds or thousands of batteries providing utility-scale services. Their size is measured in power (MW) and in energy (MWh), so a one-megawatt battery that can be fully discharged for two hours would have a rating of 1 MW and 2 MWh.

While batteries get the most attention, energy can be stored in many forms. Heat can be stored in water heaters while cold can be stored in ice systems integrated with air conditioners. Even the thermal mass of a building can be used to store heating or cooling energy. More exotic distributed storage technologies include compressed air and fluids, flow batteries, superconducting magnetic energy storage, supercapacitor (or ultracapacitor) energy storage, and flywheel systems.[46]

Battery storage is rapidly growing, but mostly for electric vehicles. Globally, 1.28 million electric vehicles were sold in 2017, including 200,000 in the US, creating demand for over 64,000 MW of battery capacity.[47] Lithium ion technology dominates the battery market currently, including over 80 percent of the stationary market.

Large-scale stationary batteries in the U.S. grew to 708 MW / 867 MWh in 2017, according to the U.S. Department of Energy (DOE).[48] Forty percent of the total capacity is the PJM Interconnection, owned by independent power producers providing power-oriented

44 *CPUC, Integrated Demand Side Management Program (2013-2014)*, March 2013, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5417, and CPUC, Proposed Decision Addressing Energy Efficiency Business Plans, April 4, 2018, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M212/K763/212763072.PDF.

45 Michael W. Jarred, ibid.

46 For more information see the Energy Storage Association at http://energystorage.org/energy-storage/energy-storage-technologies.

47 Data from EV-Volumes.com at http://www.ev-volumes.com/country/total-world-plug-in-vehicle-volumes/

48 Energy Information Administration, U.S. Battery Storage Market Trends, May 2018, https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

frequency regulation services. Large systems in California accounted for 18 percent of power capacity (MW) in 2017, but 44 percent of energy capacity (MWh), due to greater use of long-duration batteries to provide energy-related services.

Small-scale applications (less than 1 MW) added up to 66 MW nationwide, with nearly 90 percent located in California, and over half serving commercial customers.

More than 60 percent of the existing battery storage power capacity in California was installed in response to a leak at the Aliso Canyon Natural Gas Storage Facility outside Los Angeles in October 2015. By December 2016, Southern California Edison added 62 MW of battery storage to the system to preserve reliability, and San Diego Gas and Electric added another 38 MW by early 2017.

The CPUC requires resources to provide at least four hours of output to contribute to reliability reserves. As a result, large-scale battery storage installations in California tend to need larger energy capacities to qualify as reliability resources, so California installations account for 44 percent of US energy (MWh) capacity, but only 18 percent of power (MW) capacity.

Large-scale battery storage installations in CAISO have an average power capacity of 5 MW and an average duration of 4 hours. Installations in PJM, however, tend to be power-oriented with larger capacities and shorter durations to serve frequency regulation applications. PJM batteries have an average power capacity of 12 MW and an average duration of less than 45 minutes.

Ninety percent of small-scale storage in the US is in California, thanks largely to the SGIP program. Over half of US capacity is deployed on site by commercial customers in California, 30 percent at industrial sites, and only 5 percent in California homes.[49]

ii. CURRENT AND POTENTIAL DEPLOYMENT IN CALIFORNIA

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The cost of storage depends on both power and energy capacity. Short duration batteries were about $1,000 per kW of power in 2017, according to DOE, while long-term batteries averaged $2,500 per kW. Rated by energy capacity, prices ranged from $500 to $2500 per kilowatt-hour (kWh).

However, prices are falling rapidly. Tesla now sells their 7-kilowatt/13.5-kilowatt-hour Powerwall storage system for $5,900, plus hardware and installation, for a power cost of $842 per kW and energy cost of $437 per kWh.[51] On a call in June, Tesla CEO Elon Musk thought they could reach a cost of $100 per kWh within two years.[52]

49 EIA, 2018, op cit.

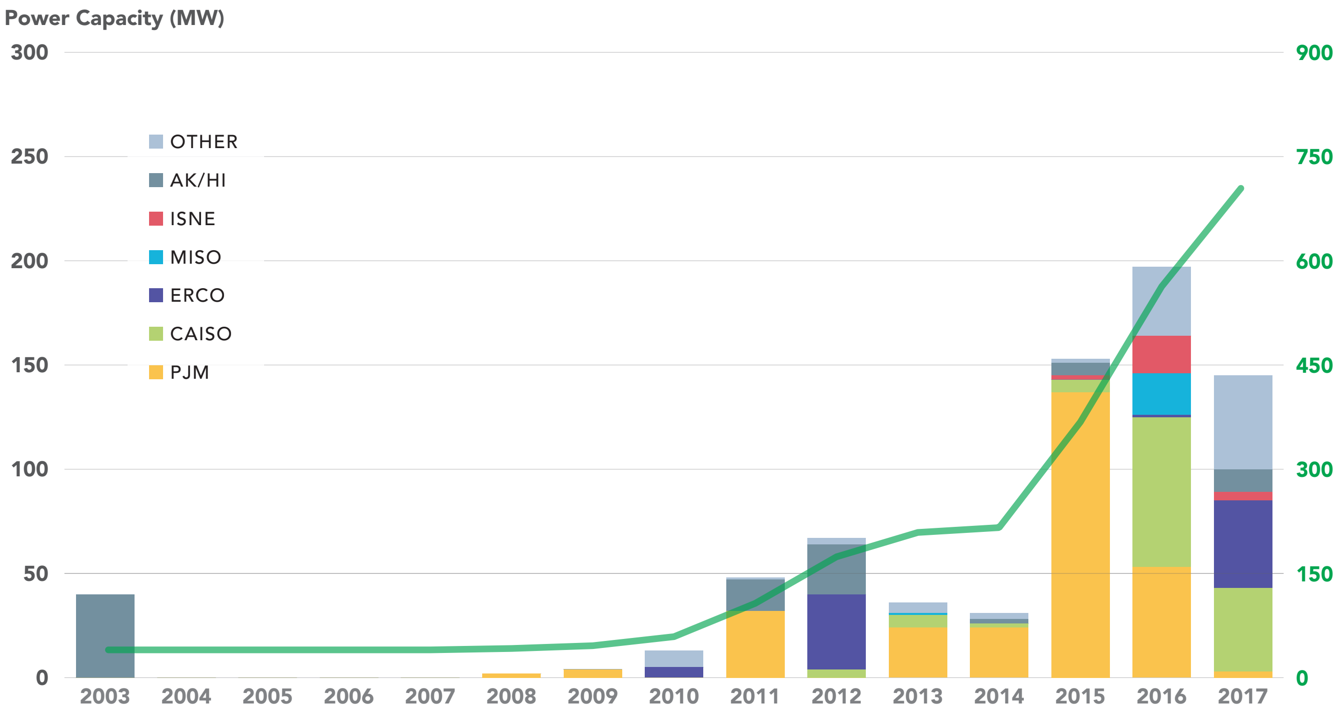
50 EIA, 2018, op cit.

51 Tesla, Powerwall web site, accessed July 2018, https://www.tesla.com/powerwall

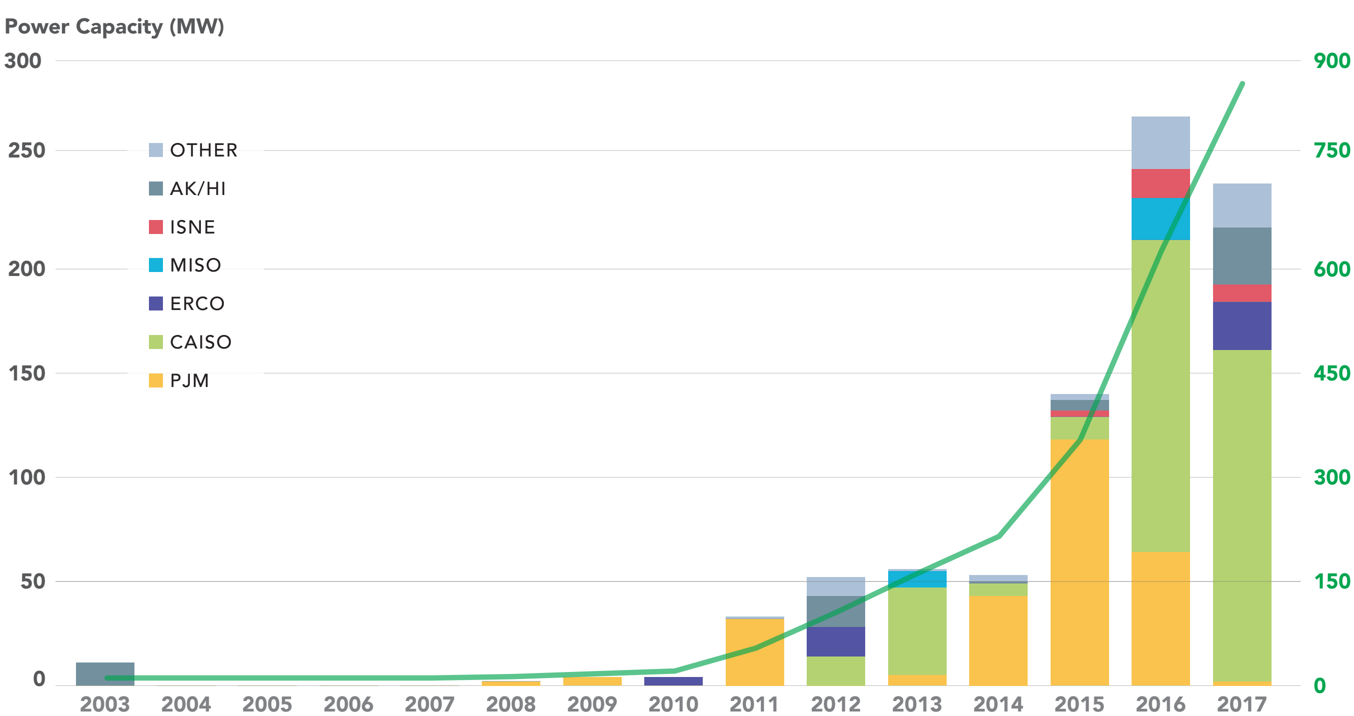
52 Fred Lambert, Electrek, "Tesla might have achieved battery energy density and cost breakthroughs," June 9, 2018, https://electrek.co/2018/06/09/tesla-battery-energy-density-cost-breakthroughs/

FIG 2 U.S. Large-Scale Battery Storage Capacity by Region (2003–2017)

Power Capacity



Energy Capacity



Source: Energy Information Administration[46]

53 EIA. "U.S. Battery Storage Market Trends" can be found at: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

Since batteries have been largely uneconomic in the past, the potential for deployment in California has been fixed by policies, especially the Self Generation Incentive Program (SGIP) and legislative mandates (AB 2514 and AB 2868, discussed in the Policies section that follows). However, as prices fall deployment will begin to exceed mandates. In June 2018, PG&E announced a deal with Tesla and others to deploy the world's largest battery project near Monterey Bay, to replace three natural gas plants.[54] (See sidebar for more details.) This project will cause PG&E to greatly exceed their mandated deployment, many years in advance.

Mandated markets for energy storage in California are currently at 1,825 MW (compared to peak summer demand of about 60,000 MW). As prices fall and utilities, aggregators, and customers adopt storage for non-mandated reasons, demand could rise substantially.

GTM Research sees U.S. demand for batteries rising from about 225 MW per year in 2016 and 2017 to 3,700 MW in 2023. About half of deployment in that year will be utility-scale with the other half divided between residential and non-residential behind-the-meter applications.[55]

GTM sees California making up 39 percent of the 2023 annual market, with 1,456 MW / 4,285 MWh. Growth will be especially strong in the residential segment, owing in large part to a shift to time-of-use rates, net metering program changes that reduce compensation for exported solar, the recently-adopted mandate for solar on new construction (which will also create more demand for storage), and a continued decline in system prices.[56]

The total market potential will hinge on a wide variety of factors, including the price and performance of batteries, their competitiveness with gas peaking plants, changes to the renewable generation mix, the relative prices for electricity under time-of-use pricing, the size

World's Largest Battery System Coming to California CA

Currently, the world's largest storage installation, this is the Tesla Powerpack paired with Neoen's Hornsdale Wind Farm near Jamestown, South Australia. The Monterey Bay one will be the world's largest once completed[57]

In June, PG&E announced the world's largest battery project, to be installed near Monterey Bay. Currently, the largest battery storage project is in Australia and uses Tesla Powerpacks (photo above). The four storage projects, totaling 567.5 MW of four-hour-duration batteries, would replace three natural gas power plants that have been given "reliability must run" status that guarantees a regulated price for power, rather than competing in the CAISO market. The CPUC asked the utility to develop a competitive alternative, and it found that storage options were less expensive than generation.

One of the projects will be a 10 MW aggregation of behind-the-meter batteries at customer sites. The other three will be large, utility-scale projects, with one owned by PG&E.

54 Pacific Gas and Electric Company, "Advice 5322-E (ID U 39 E), Public Utilities Commission of the State of California, Subject: Energy Storage Contracts Resulting from PG&E's Local Sub-Area Request for Offers Per Resolution E-4909," June 29, 2018, https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5322-E.pdf

55 GTM Research, "US Energy Storage Monitor: Q2 2018 Executive Summary," June 2018, https://www.woodmac.com/our-expertise/focus/Power--Renewables/u.s.-energy-storage-monitor-q2-2018/

56 Brett Simon, GTM Research, personal communication, July 18, 2018.

57 Tesla. Photo available at: https://www.tesla.com/blog/tesla-powerpack-enable-large-scale-sustainable-energy-south-australia

of demand charges for non-residential customers, and the growth of other DERs. One major wild card could be whether electric vehicles are used as storage devices when they are plugged in, and whether a market develops for used batteries after they have degraded from use in cars—so-called "second life" batteries. These options are discussed further in the next section.

iii. POLICIES

There is a great deal of activity in the area of energy storage policies, from both the CPUC and the legislature.

In 2013, the CPUC implemented Assembly Bill 2514, setting a mandate for investor-owned utilities to procure 1,325 MW of energy storage by 2020, across a variety of configurations and ownership models. A 2016 bill, AB 2868, ordered investor-owned utilities to procure an additional 500 MW of distributed energy storage, including no more than 125 MW of customer-sited energy storage. The Self-Generation Incentive Program (SGIP), which provides financial incentives for installing customer-sited technologies, has designated $48.5 million in rebates for residential storage systems 10 kW or smaller, and $329.5 million for storage systems larger than 10 kW.[58]

Regulators are also promoting energy storage to meet rapid reliability needs. The blowout of the Aliso Canyon Natural Gas storage facility in 2015 threatened supplies to 10,000 MW of gas-fired power plants in the Los Angeles area, prompting the CPUC to order a quick deployment of batteries. In total, Southern California Edison and San Diego Gas & Electric procured just over 100 MW / 250 MWh of storage from eight projects. The timeline from RFP to coming online was only six months.[59]

Likewise, the retirement of the San Onofre nuclear plant and of coastal plants using once-through water cooling left a major generation gap in coastal communities in Southern California. In the Local Capacity Requirements case in 2013, Southern California Edison was required to get at least 50 megawatts of energy storage but ended up signing contracts for five times that amount.[60]

[61]The main driver for distributed energy storage is the Self-Generation Incentive Program (SGIP). Launched in 2001, SGIP was initially intended to support innovative distributed generation technologies that reduced peak load. In 2011, SGIP's mission was changed to cutting carbon emissions. In 2014, as solar power became a competitive resource, the legislature and the CPUC shifted SGIP put more emphasis on batteries.[62]

In 2017, the CPUC created the SGIP Equity Budget, which allocates 25 percent of energy storage funds for projects by non-profits, small businesses, educational institutions and governments in low-income housing and in disadvantaged and low-income communities.

SGIP provides a per-kWh payment for behind-the-meter storage projects, with the amount declining in steps as volume targets are reached, the same strategy used by the successful California Solar Initiative. The current SGIP budget is $566 million, with 79 percent of funds earmarked for storage.[63] Expenditure amounts and categories change with each step, as shown in Figure __.

The CPUC is also developing policies for behind-the-meter storage systems that are paired with solar. Currently storage technologies alone are not allowed to use net metering arrangements. The CPUC initially developed guidance on these solar + storage systems in 2014 but is currently revising them to be more flexible.[64]

58 Energy Information Administration, U.S. Battery Storage Market Trends, May 2018, https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

59 David Wagman, IEEE Spectrum, "Energy Storage Rose From California Crisis," May 8, 2017, https://spectrum.ieee.org/energywise/energy/the-smarter-grid/california-crisis-tests-energy-storage-supply-chain

60 Eric Wesoff and Jeff St. John, Greentech Media, "Breaking: SCE Announces Winners of Energy Storage Contracts Worth 250MW," November 5, 2014, https://www.greentechmedia.com/articles/read/breaking-sce-announces-winners-of-energy-storage-contracts#gs.CqJZPC4

61 CPUC Self Generation Incentive Program data can be found at: http://www.cpuc.ca.gov/sgip/

62 CPUC, "About the Self-Generation Incentive Program," accessed July 2018, http://www.cpuc.ca.gov/General.aspx?id=11430

63 CPUC, "Self-Generation Incentive Program," accessed July 2018, http://www.cpuc.ca.gov/sgip/

64 Julian Spector, Greentech Media, "The Time Has Come for Battery Net Metering," April 5, 2018, https://www.greentechmedia.com/articles/read/the-time-has-come-for-battery-net-metering#gs.Y=SaJ=0 and CPUC, "Decision Regarding Net Energy Metering Interconnection Eligibility For Storage Devices Paired With Net Energy Metering Generation Facilities," Decision 14-05-033, May 15, 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M091/K251/91251428.PDF

Electric Vehicles as Grid Tools

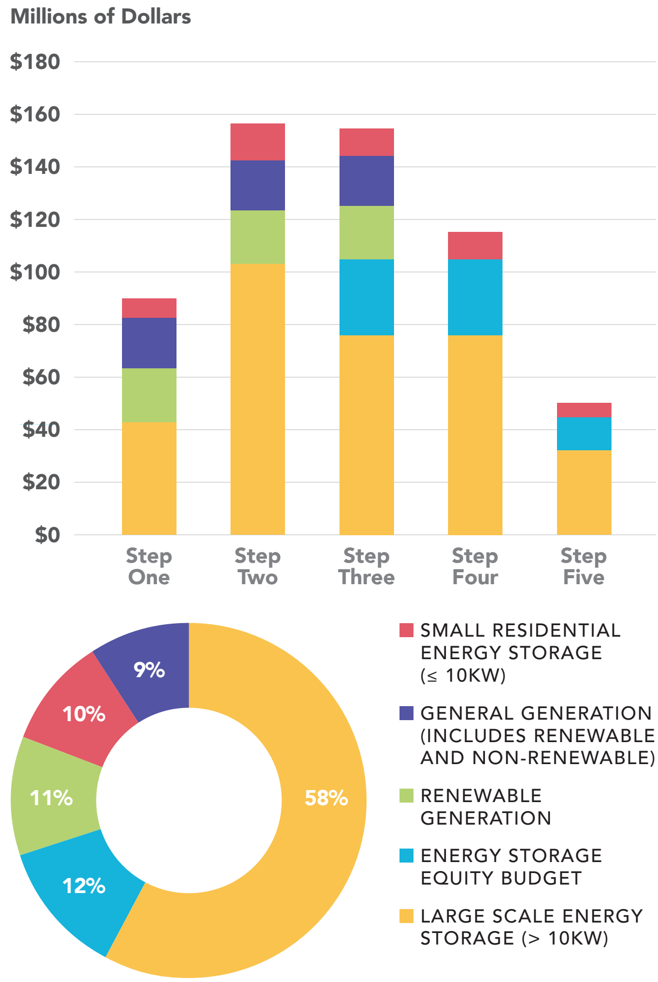
i. TECHNOLOGY BASICS

From the perspective of the electricity grid, electric vehicles are both major appliances and batteries on wheels. As an appliance, their charging can be controlled as a demand response measure, either automatically using software controls or manually in response to time-of-use rates. As batteries on wheels, they can discharge into the grid when they are parked and plugged in, just like a stationary battery. Both tasks can help fill in valleys, cut peaks, and reduce loading on local circuits, while discharging can also offer voltage and frequency support and capacity.

A battery-only electric vehicle (BEV), like Tesla cars, the Nissan LEAF, and the Chevy Bolt, currently have batteries ranging from 24 to 100 kWh, while plug-in hybrid vehicles have smaller batteries. Larger electric vehicles, such as transit buses, can have batteries as large as 660 kWh. Battery capacities are rising as manufacturers seek greater driving range.

For more information on the potential for EVs as a grid resource, see the companion Next 10 brief, Electric Vehicles and the *California Grid*.[65]

FIG 3 Self-Generation Incentive Program (SGIP)



Source: CPUC data[67]

ii. CURRENT AND POTENTIAL DEPLOYMENT IN CALIFORNIA

Governor Jerry Brown recently raised the state's goal from 1.5 million EVs by 2025 to five million on the road by 2030. BEV sales grew in 2017 to 95,000 vehicles nationwide, with cumulative sales of 400,000 since 2011. California alone accounts for half of U.S. sales, and 15 percent of global EV sales. Plug-in hybrid sales have been similar, with California accounting for 189,000 of the 395,000 in the U.S.[66]

Energy storage can be delivered by batteries from electric vehicles, either while they are parked or after they have degraded enough to impair driving performance, but can still be used for stationary use.

Research by the CPUC found that cars spend 96 percent of their time parked, making EV batteries an attractive option for grid services. Based on forecasts of 1.5 million electric vehicles on the road by 2025, the agency expected at least 7,500 MW of battery capacity in electric cars.[68]

65 *Electric Vehicles and the California Grid* is available at http://next10.org/grid-ev

66 Auto Alliance, "Advanced Technology Vehicle Sales Dashboard," accessed July 2018, https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

67 CPUC Self Generation Incentive Program data can be found at: http://www.cpuc.ca.gov/sgip/

68 Adam Langton and Noel Crisostomo, Energy Division, California Public Utilities Commission, Vehicle - Grid Integration: A Vision for Zero-Emission Transportation Interconnected throughout California's Electricity System, March 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M080/K775/80775679.pdf

Gov. Brown subsequently raised the goal to five million EVs on the road by 2030.

Electric vehicles can also provide grid services as a demand response measure, by controlling the amount and time of charging to reduce peaks and ramps and to fill in valleys.

A study by Berkeley Lab and others found that simply controlling charging for a portion of 1.5 million EVs would provide about 1 GW of value at a cost of $150 million, and displace between $1.45 and $1.75 billion worth of stationary batteries.[69] However, the cost of stationary batteries is falling rapidly, and whether car owners will participate is an unknown.

Using two-way integration (both charging and discharging vehicle batteries) could provide grid services equivalent to between $12.8 to $15.4 billion of stationary storage by 2025. The authors conclude that "funds intended to support stationary storage rollout could instead be redirected toward additional deployment and grid-integration of EVs."

When EV batteries lose 20 percent of their capability over time, they become inadequate to the heavy performance demands of a car, such as acceleration and climbing. But they can still perform well enough to provide grid services, which are less taxing, giving them a "second life." Second-life batteries are being tested at the UC San Diego microgrid, a research project in cooperation with BMW.[70]

A UCLA/UC Berkeley study found that if the battery packs from half of the 92,000 EVs on the road in California in 2014 could be repurposed for stationary use, with 75 percent of their original capacity, these second-life batteries could store and dispatch up to 850 MWh of electricity and 425 MW of power.[71] Gov. Brown's goal of 5 million vehicles is 50 times more than 2014 levels, creating an enormous wave of second-life batteries in coming decades.

iii. POLICIES[72]

California has a goal of 5 million ZEVs on the roads by 2030 and 250,000 electric vehicle charging stations by 2025. Transportation accounts for 37 percent of statewide greenhouse gas emissions, 83 percent of statewide NOx emissions and 95 percent of statewide diesel emissions, according to the Air Resources Board (ARB).[73]

Electric vehicles are supported by a variety of federal, local, and especially state policies. At the federal level, buyers can tap a tax credit of up to $7,500 per vehicle. Car makers are also subject to emission standards that encourage zero-emission vehicles, though do not require them. A number of local communities in California and elsewhere give EV owners incentives such as free parking and free or subsidized charging. Some utilities and air quality management districts offer rebates for home charging stations and low "EV incentive" charging rates.

The bulk of policies are at the state level in California. Car buyers get direct incentives, such as a tax credit of up to $,2500 per vehicle, letting drivers use carpool lanes without any other passengers, and subsidized charging infrastructure. Car makers are subject to a variety of regulations, including the state's Advanced Clean Cars law, known as ZEV-LEV, that requires car makers to get at least 16 percent of their sales from zero-emission vehicles by 2025.[74]

Fuel sellers are subject to the Low Carbon Fuel Standard (LCFS), which requires reductions in the life-cycle carbon content of fuels. Electric vehicles are one way to earn LCFS credits, which can be sold to fuel companies.[75]

69 Jonathan Coignard, Samveg Saxena, Jeffery Greenblatt, and Dai Wang, Environmental Research Letters, "Clean vehicles as an enabler for a clean electricity grid," May 16, 2018, http://iopscience.iop.org/article/10.1088/1748-9326/aabe97/pdf

70 California Energy Commission, "California Energy Storage Showcase: New Life for Electric Vehicle Batteries," accessed May 2018, http://www.energy.ca.gov/research/energystorage/tour/ev_batteries/

71 Ethan N. Elkind, UCLA School of Law and UC Berkeley School of Law, *REUSE AND REPOWER: How to Save Money and Clean the Grid with Second-Life Electric Vehicle Batteries*, September 2014, https://www.law.berkeley.edu/files/ccelp/Reuse_and_Repower_--_Web_Copy.pdf

72 BMW. Photo from: http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf

73 CPUC, Zero-Emission Vehicles, accessed July 2018, http://www.cpuc.ca.gov/zev/

74 ARB, "The Advanced Clean Cars Program," accessed July 2018, https://www.arb.ca.gov/msprog/acc/acc.htm

75 ARB, "Low Carbon Fuel Standard," accessed July 2018, https://www.arb.ca.gov/fuels/lcfs/lcfs.htm

The state has a number of funds to support deployment of charging infrastructure, including the $423 million Volkswagen (VW) Environmental Mitigation Trust, created when the car maker was caught cheating on emission tests. The settlement also requires VW to invest $800 million in charging infrastructure in California.[76]

Until recently utilities were not allowed to own or invest in charging infrastructure, since it was considered a service that the competitive market would provide. While commercial charging has expanded from companies like evGo, Tesla, and Chargepoint, regulators thought the speed of deployment was too slow to meet state goals.

In June 2018, the CPUC approved $768 million in funding for utilities to support the deployment of charging stations and sales of medium- and heavy-duty electric vehicles. The programs are part of a directive of Senate Bill 350 that requires utilities to undertake transportation electrification activities.[77]

Now that vehicles and infrastructure are rolling out, regulators are paying more attention to vehicle grid integration policies to encourage their use as demand response and storage resources.

EV owners can sign up for special EV rates, which are lower during off-peak times, similar to standard time-of-use rates. Such rates will be the default option for residential customers starting in 2019.

Regulators have been using pilot projects to study "smart charging" policies, where the rate and timing of charging can be controlled by the customer or by an aggregator in order to participate in demand response programs. One example, from BMW and Pacific Gas & Electric, is described in the sidebar.[78]

California is also still testing vehicle grid integration (VGI, also known as "vehicle to grid" or V2G) strategies with pilot programs. The Los Angeles Air Force Base tested the ability of the base's 41 EVs to bid directly into CAISO markets to provide up and down regulation services. The pilot operated successfully from January 2016 to September 2017, but due to its small size the revenues from selling energy services were less than the participation fees charged by CAISO. A larger project or a bigger aggregator would see more favorable economics.[79]

Sonoma Clean Power offers customers a free home EV charging station in exchange for participating in the CCA's "Grid Savvy" demand response program. SCP has supported the sale of 771 EVs since 2016 with rebates and dealer incentives, with a goal of 100,000 by 2030. So far 606 EV owners have signed up for the Grid Savvy program. SCP expects to call no more than 10 DR events a month, and hopes to expand the program later this year to other devices such as heat pump water heaters, smart thermostats, and residential battery storage.[80]

76 ARB, "Volkswagen Settlement - Environmental Mitigation Trust for California," accessed July 2018, https://www.arb.ca.gov/msprog/vw_info/vsi/vw-mititrust/vw-mititrust.htm

77 Emma Foehringer Merchant, Greentech Media, "California Regulators Approve Landmark Utility EV-Charging Proposals," May 31, 2018, https://www.greentechmedia.com/articles/read/california-cpuc-approves-landmark-ev-charging-proposals#gs.M=T0VoM

78 BMW and PG&E, *BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot*, June 2017, http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf

79 Anand Gopal, ibid.

80 Sonoma Clean Power, "Get a Smart Charger and Join GridSavvy!" accessed July 2018, https://sonomacleanpower.org/gridsavvy/; 2017 annual report at https://sonomacleanpower.org/2017-annual-report/; and personal communication with SCP, July 17, 2018.

Communication and Control

i. TECHNOLOGY BASICS

DERs also include technologies that facilitate communication and control of energy technologies, both for power and grid companies and for customers.[81]

The most fundamental device is the digital meter, which is in the process of replacing the analog "spinning dial" meter worldwide. These "smart" meters can have varying levels of ability. The most basic can report consumption wirelessly, eliminating the need to have people walk from house to house reading meters. More sophisticated advanced metering infrastructure (AMI) can track consumption by the hour and report it in real time, both to the utility and to the consumer. AMI enables time of use rates and peak demand charges that can guide consumer behavior, and that are fundamental to valuing DERs of all kinds.

Grid operators are enjoying a revolution in their ability to monitor and control their systems. Up until recently a utility would learn about a failure on their distribution grid only when they were called by a customer. Now they are able to use Supervisory Control and Data Acquisition (SCADA) systems and phasor measurement units (PMUs) to monitor the operation of circuit breakers and take sections of the power grid online or offline.

The equivalent for distributed energy technologies is known as Distributed Energy Resource Management Systems (DERMS), which provide communication and control with DERs on the grid. By controlling many distributed technologies, grid operators or third-party companies are able to aggregate them into the same kinds of services that used to be provided exclusively by power plants. Aggregators can bid bundled DERs into wholesale markets to provide capacity and energy, as well as grid services.

PG&E/BMW Pilot Project

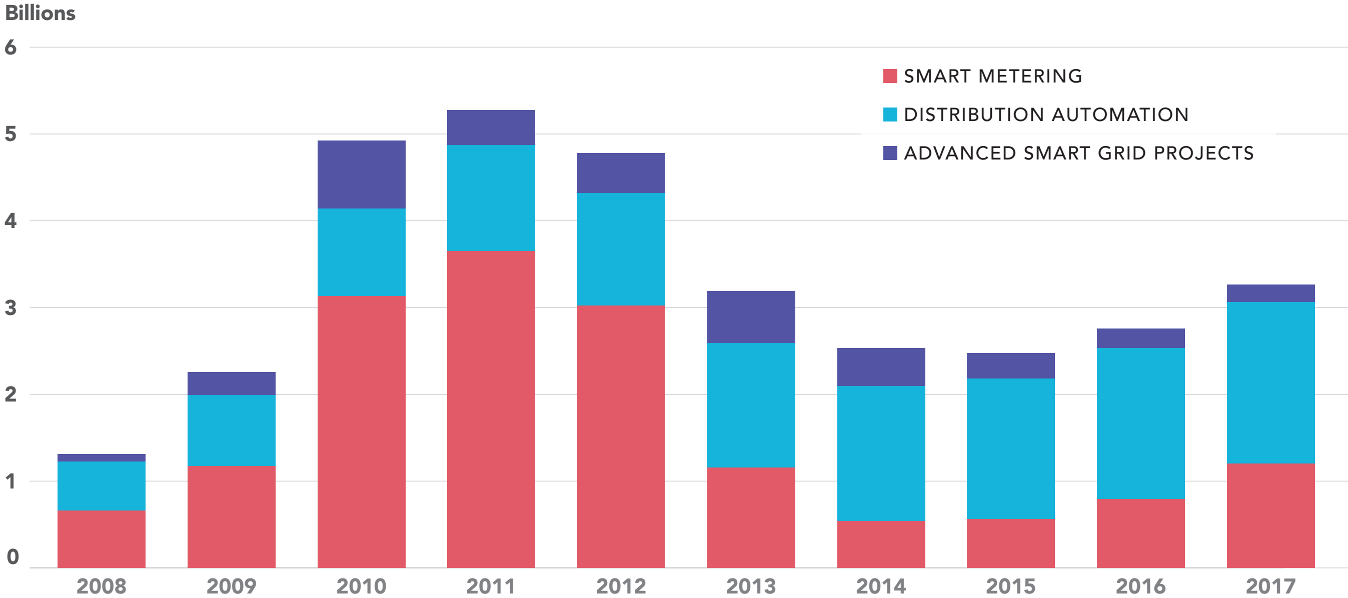
BMW i ChargeForward Program[82]

BMW partnered with Pacific Gas & Electric in 2015 and 2016 on the Charge Forward project. The pilot tested 96 BMW i3 vehicles and a 225 kW "second-life" stationary battery system composed of eight used EV battery packs with 209 demand response events. The cars and battery packs were able to provide DR services as a flexible grid resource. The stationary batteries were tapped the most, since participation by the cars was limited by a lack of access to workplace charging for daytime DR events. A second phase is underway that looks into more advanced charging management and more communications to the vehicle and driver.

81 For more details see US DOE, Quadrennial Technology Review: An Assessment Of Energy Technologies and Research Opportunities; Chapter 3: Enabling Modernization of the Electric Power System, September 2015, https://www.energy.gov/sites/prod/files/2017/03/f34/qtr-2015-chapter3.pdf

82 BMW. Photo from: http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf

FIG 4 Spending on Smart Grid Technologies, 2003–2008, with Projections to 2017



Source: U.S. Department of Energy[85]

Likewise, software controls can provide services to building owners and campuses. Building Energy Management Systems (BEMS) monitor, control, measure, and optimize the energy consumption of devices used by a building, like lighting and HVAC. They can collect data that enables building and facility managers to identify areas of improvement, but they can also control demand as part of demand response programs, cutting costs and earning revenues.

BEMS can be done remotely, allowing companies to offer energy management as a service to building owners. The company EnerNoc, for example, manages office buildings in California from a control center in Boston.[83]

Software can also control a specific energy system or be embedded in appliances. Digital thermostats, for example, can be programmed to run heaters and air conditioners at off-peak times, saving money for the homeowner. More sophisticated controllers, like the NEST Learning Thermostat, connect to the internet, allowing a utility or third-party company to control HVAC equipment to shift demand. Austin Energy, in Texas, pays residential customers to give control of their thermostat (within limits) to the utility, which can cut air conditioning demand during peak periods, saving money for all of their customers. Austin Energy estimates that the 13,000 participating homes create savings of $700,000 per year and cut peak demand by 15 MW.[84]

ii. CURRENT AND POTENTIAL DEPLOYMENT IN CALIFORNIA85

California was an early adopter of smart metering infrastructure, with the CPUC ordering full deployment in 2003. Deployment was boosted nationally by the American Reinvestment and Recovery Act (ARRA), the stimulus bill from 2008. Boosted by ARRA funding, almost $10 billion was invested in smart meter conversions nationwide from 2010 to 2012, as shown in Figure 4. As of 2016, 43 percent of all meters in the U.S. had advanced metering capability. The Western U.S. had the second highest

83 EnerNOC, demand response products, accessed May 2018, https://www.enernoc.com/products/businesses/capabilities/demand-response

84 Debbie Kimberly, Austin Energy, "The Rising Value of Residential Demand Response," Electric Light & Power Magazine, February 22, 2017, https://www.elp.com/articles/powergrid_international/print/volume-22/issue-2/features/the-rising-value-of-residential-demand-response.html

85 DOE. "QTR" can be found at: https://www.energy.gov/sites/prod/files/2017/03/f34/qtr-2015-chapter3.pdf

penetration rate, at 60 percent.[86] California IOUs had completed installation of 12 million meters by 2012, with only 54,000 customers opting out.[87]

The biggest current trend in smart grid investment nationally and in California is to automate distribution system controls, with nearly $2 billion invested last year. California utilities invested nearly $250 million in 2016-2017 alone, far outpacing other categories of investment (see Figure 4).[88]

The Electric Power Research Institute has estimated that full US grid modernization would require between $338 and $476 billion of new investment over the next twenty years.[89]

iii. POLICIES IN CALIFORNIA

For utility-facing technologies, investments in communication and control technologies are determined by regulators based on a cost-benefit analysis. As mentioned above, California regulators have been early supporters of advanced technologies, partly because they are the enabler of many policies and technologies intended to improve efficiency and support DER technologies. The move to default time-of-use rates for residential customers, for example, would not be possible without smart meters that can track energy use by specific time categories. Investments in distribution and transmission control systems have favorable cost-benefit ratios due to improved reliability, quicker response to outages, greater safety, more efficient maintenance and repair, and greater visibility into operations.

Smart grid investments have been directed by both legislation and regulatory decisions, including utility Distribution Resource Planning (DRP), which started in 2015. Some key aspects of DER planning are 1) to determine Locational Net Benefits, or how the value of DERs varies based on their location on the distribution grid, and 2) to gauge the capacity of the distribution grid to host DERs (called Integration Capacity Analysis). Communication and control technologies are critical in tracking grid operations at the distribution level, thus determining relative values and capacity.[90]

Investments in customer-facing communication and control technologies are made by customers, typically by facilities managers that see benefits from greater efficiency, participation in demand response and other energy markets, and visibility into operations. As with all DERs, consumer decisions are influenced by all DER policies, especially those that monetize the value of DER technologies.

86 Federal Energy Regulatory Commission, *2017 Assessment of Demand Response and Advanced Metering, Staff Report*, ibid.

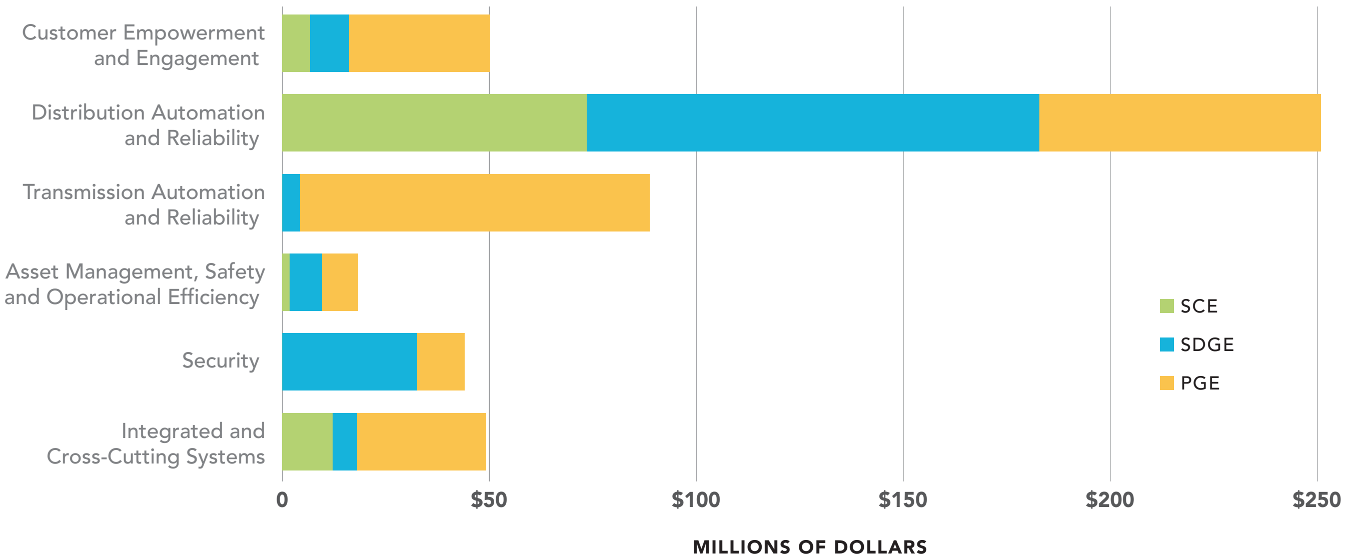
87 CPUC, *California Smart Grid Annual Report to the Governor and the Legislature in Compliance with Public Utilities Code § 913.2*, February 2018, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Smart%20Grid%20Annual%20Report%202017.pdf

88 CPUC, ibid.

89 Electric Power Research Institute, Estimating the Costs and Benefits of the Smart Grid, March 2011, https://www.smartgrid.gov/files/Estimating_Costs_Benefits_Smart_Grid_Preliminary_Estimate_In_201103.pdf

90 CPUC, *California Smart Grid Annual Report to the Governor and the Legislature in Compliance with Public Utilities Code § 913.2*, February 2018, ibid.

FIG 5 Smart Grid Deployment by California IOUs, 2016–17



Source: CPUC[91]

Microgrids

i. TECHNOLOGY BASICS

DERs can be aggregated together into a microgrid. A microgrid is typically a small group of buildings, like a military base or a college campus, but can be smaller or larger (and thus called a nanogrid or mini-grid). Microgrids can operate independently from the grid, if configured to "island" during a power outage, or they can be grid dependent, offering benefits to the customer and to the grid operator. They typically have one or more generators, energy storage, and controls.

According to one estimate, there are 1,900 operating or planned microgrids in the U.S., though many of these are "basic" microgrids, with just a diesel generator and a switch to disconnect a building from the grid. The U.S. military has a strong interest in microgrids to make bases more secure and to provide energy in the field that relies less on delivered fuel. Navigant Research estimates the military could spend $billion on microgrids by 2026.

Control Systems Installed at San Diego Military Bases

These solar panels are part of the Marine Corps Air Station Miramar's microgrid system, designed to provide a reliable and renewable energy source that can be monitored and controlled independently of the grid.[90]

Navy and Marine Corps facilities in San Diego have installed a supervisory control and data acquisition (SCADA) system to monitor and control electrical and mechanical systems, emissions controls, and building systems. One application of the system is to manage a microgrid at the Marine Corps Air Station Miramar that features distributed generation and storage.

91 CPUC. "Smart Grid Annual Report" can be found at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Smart%20Grid%20Annual%20Report%202017.pdf

92 Marine Corps Air Station Miramar. Photo by Lance Cpl. Jake McClung. Available at https://www.miramar.marines.mil/Photos/igphoto/2001650747/

ii. CURRENT AND POTENTIAL DEPLOYMENT IN CALIFORNIA

As of early 2017, there were 36 operating microgrids in California, with an additional 80 under construction or planned. Altogether the systems will have over 650 MW of peak capacity. Almost half the generating capacity at existing microgrids is from solar panels, while 34 of the systems are on institutional campuses, such as schools and office parks. There are a higher number of microgrid systems in Alaska (such as remote villages) and in New York.

iii. POLICIES IN CALIFORNIA

From the perspective of the grid, a microgrid is a single customer with a single interconnection and point of metering. Thus, like any customer, a customer with a microgrid is affected by distributed generation policies like net metering, interconnection, and rate designs. Because a microgrid offers greater control and flexibility, they are good candidates for demand response programs.

Still, there is no specific goal or policy for the deployment of microgrids. One ongoing issue is that while microgrids could serve multiple customers in a community microgrid, state law says that if electricity sold to another person crosses a public street it is considered an "electrical corporation" and becomes a "public utility subject to the jurisdiction, control, and regulation of the commission."[93]

Current policies, according to a CPUC staff report, "envision a particular service and regulatory model that is increasingly strained by the development of policies related to solar, net energy metering, distributed generation, and behind-the-meter microgrids."

Stone Edge Farm Microgrid

Microgrid at Stone Edge Farm in Sonoma, California, using technology provided by Emerson[96]

The Stone Edge Farm in Sonoma county is a wine and produce farm that has made itself a test bed of cutting edge microgrid technologies. The microgrid has six different battery technologies, solar panels, and produces hydrogen with an electrolyzer that is used in a fuel cell and in fuel cell cars. They are working to convert a natural gas microturbine to run on hydrogen as well. The microgrid is able to operate the farm while disconnected from the grid during an outage, which it did during the Sonoma fires of 2017. It won a Governor's Environmental and Economic Leadership Award in January of 2018.[94]

The CPUC, CAISO, and the Energy Commission are convening stakeholders to develop a Microgrid Roadmap, which was released in draft form in September 2017.[94] The Energy Commission is in the process of funding $50 million to up to 12 pilot projects to help clarify the business case for and benefit metrics of microgrids.[95]

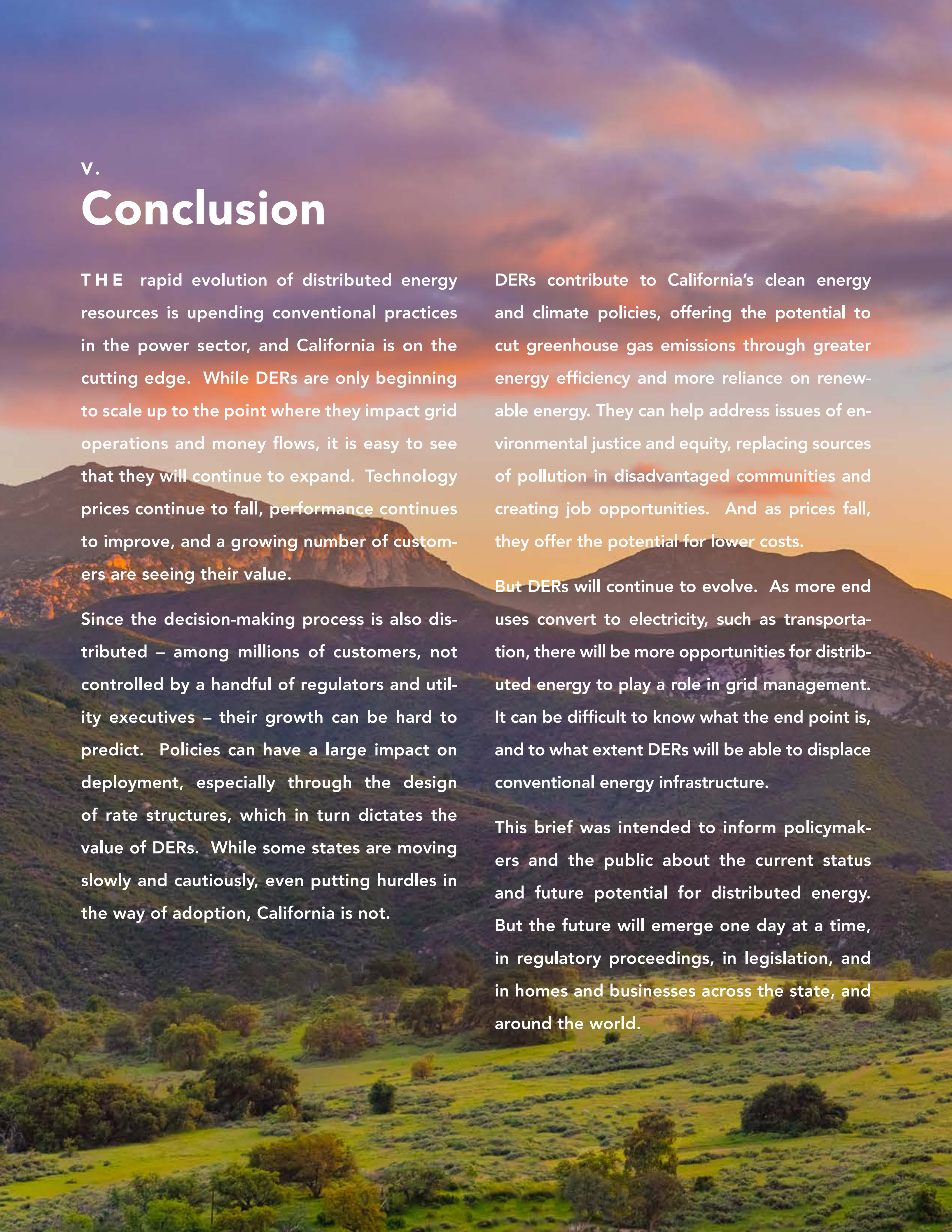
93 Christopher Villarreal, et al., CPUC Policy and Planning Division, *Microgrids: A Regulatory Perspective*, April 14, 2014, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5118

94 CEC, CPUC, and CAISO, *Roadmap for Commercializing Microgrids in California (Draft)*, September 2017, http://docketpublic.energy.ca.gov/PublicDocuments/16-EPIC-01/TN221347_20170929T154043_Roadmap_for_Commercializing_Microgrids_in_California.pdf

95 CEC, *Grant Funding Opportunity: Demonstrate Business Case for Advanced Microgrids in Support of California's Energy and GHG Policies (GFO-17-302)*, released August 2017, https://www.energy.ca.gov/contracts/epic.html#GFO-17-302

96 Stone Edge Farm. Photo from: http://www.emerson.com/en-us/news/corporate/stone-edge-selects-emerson

97 Stone Edge Farm Microgrid, http://sefmicrogrid.com/, and Lisa Cohn, "Microgrid Kept Power On Even as the California Wildfires Caused Outages," Microgrid Knowledge, October 27, 2017, https://microgridknowledge.com/islanded-microgrid-fires/



V.

Conclusion

THE rapid evolution of distributed energy resources is upending conventional practices in the power sector, and California is on the cutting edge. While DERs are only beginning to scale up to the point where they impact grid operations and money flows, it is easy to see that they will continue to expand. Technology prices continue to fall, performance continues to improve, and a growing number of customers are seeing their value.

Since the decision-making process is also distributed – among millions of customers, not controlled by a handful of regulators and utility executives – their growth can be hard to predict. Policies can have a large impact on deployment, especially through the design of rate structures, which in turn dictates the value of DERs. While some states are moving slowly and cautiously, even putting hurdles in the way of adoption, California is not.

DERs contribute to California's clean energy and climate policies, offering the potential to cut greenhouse gas emissions through greater energy efficiency and more reliance on renewable energy. They can help address issues of environmental justice and equity, replacing sources of pollution in disadvantaged communities and creating job opportunities. And as prices fall, they offer the potential for lower costs.

But DERs will continue to evolve. As more end uses convert to electricity, such as transportation, there will be more opportunities for distributed energy to play a role in grid management. It can be difficult to know what the end point is, and to what extent DERs will be able to displace conventional energy infrastructure.

This brief was intended to inform policymakers and the public about the current status and future potential for distributed energy. But the future will emerge one day at a time, in regulatory proceedings, in legislation, and in homes and businesses across the state, and around the world.