California Public Utilities Commission

California Smart Grid

Annual Report to the Governor and the Legislature

in Compliance with Public Utilities Code § 913.2

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Table of Contents

List of Tables and Figures

Glossary of Terms

Advanced Distribution Management System: (ADMS) See Distribution Management System.

Advanced Metering Infrastructure: (AMI) refers to the full energy consumption data measurement and collection system that includes Smart Meters at the customer site, communication networks between the customer and utility, and data reception and management systems that make the information available to the utility.

Behind-the-Meter: (BTM) refers to electrical equipment and technologies that are interconnected on the customer's side of the electric meter. Customer-sited distributed energy resources (DERs) are one of the most common examples of BTM resources.

CAISO: California Independent System Operator maintains reliability on one of the largest and most modern power grids in the world, and operates a transparent, accessible wholesale energy market.

Circuit: A network of wires that carries power from substations or distributed generation to local load areas such as commercial and residential areas.

Click-Through Authorization Process: An online customer authorization process that allows customers to easily share their energy data with third-party demand response providers who can use the data to help the customer optimize their demand response performance.

Customer Minutes of Interruption: (CMI or CMIN) refers to the duration of an outage event measured in minutes summed across all customers affected by the event.

Demand Response: (DR) refers to changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Distributed Energy Resources: (DERs) include: distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. DERs are connected to the distribution grid both behind the customer's meter (BTM) and in front of the customer's meter (IFM).

Distribution Feeder: (Or feeder) refers to a circuit that carries power from a distribution substation to local load areas such as commercial and residential areas.

Distribution Investment Deferral Framework: (DIDF) a framework designed to identify opportunities where future distribution system upgrades can be deferred or avoided through distributed energy resource deployment.

Distribution Management System: (DMS, also referred to as Advanced Distribution Management System (ADMS)) a software platform that can monitor and control the distribution system efficiently and reliably.

Distribution Planning Advisory Group: (DPAG) a body formed by market participants and an independent professional engineer who advise the utilities on the selection of distribution deferral opportunities and provide input on the development of competitive solicitation for distributed energy resources.

Distribution Resources Plan: (DRP) refers to the plans that each of the investor-owned utilities were required to develop to propose contracts, tariffs or other distribution energy resources procurement mechanisms to maximize the locational benefits and minimize the incremental costs of distributed resources. The DRPs also identify additional spending necessary to integrate distribution energy resources into distribution planning and to modernize their electric grids; as well as identify the barriers to the deployment of distribution energy resources. DRP also refers to the namesake proceeding in which the DRPs were developed.

Demand Response Auction Mechanism: (DRAM) a competitive solicitation mechanism run by the investor-owned utilities that enables distributed energy resource aggregators to offer their services to utilities and the state's wholesale energy markets. The commodity being traded is measured in kilowatt-months of capacity, or the ability to reduce use or add energy for up to 4 hours at a time during the state's late afternoon and evening peaks, over the course of a month.

Electric Tariff Rule 21: (Or Rule 21) refers to the tariff governing the utilities' interconnections of distributed energy resources.

Energy Atlas: A geospatial analytical tool developed by UCLA's California Center for Sustainable Communities Institute of the Environment. The Energy Atlas is the largest set of disaggregated energy data in the nation, and uses energy consumption data at the building level, combined with public records, to reveal previously undetectable patterns about how people, buildings and cities use energy. The tool helps regional planners and decision makers more effectively target energy program interventions and develop policies to mitigate and prepare for climate change.

EV: Electric vehicle. See plug-in electric vehicle.

Fast Track Process: A streamlined review process within Rule 21 that is based on multiple evaluation screens for interconnecting net energy metering, non-export, and small exporting facilities.

Fault Location Isolation and Service Restoration: (FLISR) a software system integrated into the utilities' outage management system that limits the impact of outages by quickly opening and closing automated switches and reconfiguring the flow of electricity through a circuit. By reconfiguring the flow of electricity, FLISR can minimize the number of customers impacted by an outage and isolate the outage to reduce restoration times. With FLISR, outages that may have been a one- to two-hours in duration can be reduced to less than five minutes.

General Rate Case: (GRC) General rate cases are proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. For California's three large investor-owned utilities (IOUs), the GRCs are parsed into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect, while Phase II determines the share of the cost each customer class is responsible for and the rate schedules for each class. Each large electric utility files a GRC application every three years.

Gigawatt: (GW) a unit of electric power equal to one billion watts.

Home Area Network: (HAN) a communication network that is deployed and operated in a small area such as a house or small office that enables the communication of various devices such as distributed energy resources, heating and air-conditioning units, and smart household appliances for purposes of energy management and responding to variable energy price signals. Utilities can leverage HANs to manage customer load during peak hours and reduce greenhouse gas emissions from expensive gas-fired power plants that would otherwise be needed to meet peak demand.

Integrated Capacity Analysis: (ICA) quantifies the available hosting capacity of every distribution circuit in the utilities' service territories to integrate distributed energy resources without triggering grid upgrades.

Integrated Distributed Energy Resources: (IDER) refers to the Commission's strategy for the utilities to integrate customer demand-side programs, such as energy efficiency, self-generation, advanced metering, and demand response, in a coherent and efficient manner. Also refers to the IDER proceeding which is focused on developing sourcing mechanisms for the procurement DERs that advance distribution planning objectives.

Integrated Resource Plan: (IRP) comprehensive utility procurement plans that detail what resources are to be procured and how it will be done to comply with the State's climate and energy policies and adequately balance safety, reliability, cost and meet the State's environmental goals laid out by SB 350 and SB 100.

Inverter: An electronic device that converts DC power to AC power and is necessary to connect most distributed energy resources to the grid. See Smart Inverter.

IOU: Investor-owned utility.

Island Mode: Refers to when a circuit or microgrid operates in isolation from the distribution grid and can continue to serve power through DERs when the distribution grid experiences outages and can no longer serve the circuit or microgrid.

Kilowatt: (kW) A unit of electric power equal to one thousand watts.

Load: The total amount of power needed to meet all demand on the grid at any given time.

Locational Net Benefits Analysis: (LNBA) a tool that can determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid traditional distribution system investments.

Megawatt: (MW) a unit of electric power equal to one million watts.

Multiple-Use Applications: (MUA) refers to the multiple benefits and services that energy storage devices can provide to the grid to increase the economic value provided.

Net Energy Metering: (NEM) Customers who install small solar, wind, biogas, and fuel cell generation facilities to serve all or a portion of onsite electricity needs are eligible for the state's net metering program. NEM allows customers who generate their own energy ("customer-generators") to serve their energy needs directly onsite and to receive a financial credit on their electric bills for any surplus energy fed back to their utility.

Order Instituting Rulemaking: (OIR) An investigatory proceeding opened by the PUC to consider the creation or revision of rules or guidelines in a matter affecting more than one utility or a broad sector of the industry. Comments and proposals are submitted in written form. Oral arguments or presentations are sometimes allowed.

On-Peak: Refers to the hours of the day in which demand for electricity tends to be the highest.

Off-Peak: Refers to the hours of the day that are not characterized by on-peak electricity demand.

Outage Management System: (OMS) a computer system used by electric distribution system operators to assist in restoration of power.

PEV: Plug-in electric vehicle. A type of zero emission vehicle (ZEV) which has no tail pipe emissions. A plug-in electric vehicle is any motor vehicle that can be recharged from an external source of electricity, such as wall sockets, and the electricity stored in the rechargeable battery packs drives or contributes to drive the wheels.

Plug-and-Play: Refers to a distribution grid system where high penetrations of distributed energy resources can be integrated seamlessly due to streamlined and simplified processes for interconnecting these technologies.

Reactive Power Priority: A mandatory smart inverter setting for California's investor-owned utilities that allows distributed generation to provide local voltage support and mitigate voltage rise on the distribution system.

Reliability: The ability of the electric grid to deliver electricity in the quantity and with the quantity demanded by customers while minimizing service interruptions. Reliability is measured by the number of outages and outage duration.

Request for Offer: (RFO) an open and competitive solicitation process whereby an organization requests the submission of offers in response to a scope of services that is needed.

Resiliency: The ability of the grid to resist failure, reduce the magnitude and/or duration of disruptive events to the grid, and recover from disruptive events.

Resource Adequacy: a regulatory requirement designed to provide sufficient resources to the California Independent System Operator to ensure the safe and reliable operation of the grid in real time. RA is a planning reserve margin of available generation resources.

Self-Healing Benefits: Refers to system reliability benefits derived from a network of sensors, automated controls, and advanced software that utilize real-time distribution data to detect and isolate faults and to reconfigure the distribution network to minimize the customers impacted by outages and other disruptive events.

SIWG: Smart Inverter Working Group is an ad-hoc collaborative stakeholder committee that provides input and recommendations to the CPUC Rule 21 proceeding in the areas of smart inverters.

Supervisory Control and Data Acquisition: (SCADA) is a system of software and hardware elements that allow distribution system operators to remotely gather, monitor, and process data from sensors deployed along the distribution system.

Smart Inverter: A smart inverter is an inverter that performs functions that, when activated, can autonomously contribute to grid support during excursions from normal operation voltage and frequency system conditions. Smart inverters provide autonomous responses to voltage and frequency conditions, safety features, and communications capabilities. See Inverter.

Smart Meter: An electronic meter that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing. A smart meter enables customers to view their consumption hourly to enable improved energy management and responsiveness to time variant energy price signals. See Advanced Metering Infrastructure.

SONGS: Refers to the former San Onofre Nuclear Generating Station.

Time of Use Rates: (TOU) Time-of-use is a rate plan in which rates vary according to the time of day, season, and day type (weekday or weekend/holiday). Higher rates are charged during the peak demand hours and lower rates during off-peak (low) demand hours. Rates are also typically higher in summer months than in winter months. This rate structure provides price signals to energy users to shift energy use from peak hours to off-peak hours. Time of use pricing encourages the most efficient use of the system and can reduce the overall costs for both the utility and customers.

Truck Roll: A utility dispatch of technicians to investigate electrical equipment during an outage.

Vehicle-Grid Integration: (Also referred to as Vehicle-to-Grid Integration or VGI) a framework for utilizing the flexible charging and discharging capabilities of plug-in electric vehicles to serve as a grid asset.

Volt Amperes Reactive: (VAR) a measure of reactive power, which exists in an AC circuit when the current and voltage are not in phase. Certain types of loads absorb or produce reactive power, so its presence on the distribution grid is unavoidable. However, reactive power imbalances cause abnormal voltages, so VARs must be managed to keep line voltages within acceptable ranges.

Volt/VAR Control: (Also known as Volt/VAR Optimization) refers to the process of managing voltage levels by injecting or absorbing reactive power (measured in VAR) on the distribution system.

CPUC Smart Grid Vision

Innovation continues to create new opportunities across the network of physical, electronic, and virtual assets that make up our rapidly modernizing grid. As new ideas are tested by the physics and economics of real circuits and real-time markets, the Commission will be closely watching the outcomes and evaluating our own policies. Distributed energy resources and other smart grid technologies that empower customers to use cleaner, safer, and more affordable energy will make a lasting contribution to California's climate and economy.

In 2018, the Commission continued to make great strides towards achieving the state's Smart Grid goals. We approved pilot electric vehicle-grid integration programs. We adopted a new, annual process that requires utilities to consider solar, storage, and other distributed energy resources as they plan grid infrastructure improvements. We also adopted a new grid modernization framework to improve tracking of utility smart grid investments. We adopted a joint Commission-CAISO framework for how storage can participate in multiple markets. We approved a new set of advanced functions for smart inverters, one of which became mandatory in June. The Commission also approved over two dozen new utility contracts totaling over 1.1 GW of capacity with a wide variety of innovative distributed energy resource projects, including demand response, storage, and solar combined with storage.

- Michael Picker, President, California Public Utilities Commission, December 2018.

1. Executive Summary

This Annual Report on California's Smart Grid activities provides an overview of the California Public Utility Commission's (CPUC's or the Commission's) recommendations for a Smart Grid. It also reviews the plans and deployment of Smart Grid technologies by the state's three largest electric Investor-Owned Utilities (IOUs or the Utilities),[1] and the IOUs' estimates for the costs and benefits to ratepayers.[2]

This report will detail the following:

- CPUC Smart Grid-related activities in 2018 (Section 2);
- IOU Smart Grid project reports and overall ratepayer costs and benefits. (Section 3); and
- CPUC Smart Grid activities that are expected in 2019 (Section 3.2).

Highlights of the 2018 CPUC Smart Grid-related activities include:

- **CPUC Distributed Energy Resources (DER)[3] Action Plan[4] –** The Commission continues to implement its vision to support California's DER future to facilitate proactive, coordinated, and forward-thinking development of DER-related policy. The Commission is on course to complete actions in each of three tracks identified in the DER Action Plan: Rates and Tariffs; Distribution Planning, Infrastructure, Interconnection and Procurement; and Wholesale DER Market Integration and Interconnection.
- **Distribution Resources Plan (DRP)** –The Commission adopted two decisions on DRP policy issues. The first decision (D.18-08-004)[5] approved the methodology and process for updating the DER Growth Scenarios in distribution planning and adopted the Distribution Investment Deferral Framework (DIDF), to plan and procure DERs to defer distribution system investments. The

[1] The three largest California IOUs are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

[2] "…the commission shall report to the Governor and the Legislature on the commission's recommendations for a Smart Grid, the plans and deployment of Smart Grid technologies by the state's electrical corporations, and the costs and benefits to ratepayers." (Pub. Util. Code § 913.2).

[3] DERs are defined in Pub. Util. Code § 769 as renewable distributed generation, energy storage, demand response, energy efficiency, and electric vehicles.

[4] The DER Action Plan is available at the Energy Division's Energy Reports and Whitepapers page: http://www.cpuc.ca.gov/energy_reports/.

[5] See the following link for the text of D.18-08-004: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M221/K552/221552166.PDF.

second decision D.18-03-023)[6] adopted the Grid Modernization Investment Framework that provides guidance to the Commission in future General Rate Cases for funding requests on technological upgrades needed to integrate DERs into the grid. The IOUs implemented the first annual cycle of the DIDF in compliance with the decision.

- **Integrated Distributed Energy Resources (IDER)** – The Commission approved four Southern California Edison (SCE) in-front-of-the-meter energy storage contacts, totaling 9.5 MW, for Distribution Deferral and Resource Adequacy. The Commission approved PG&E's request to issue a competitive request for offer (RFO) to procure DERs that could displace or defer the need for capital expenditures on traditional distribution infrastructure. PG&E issued this RFO in late 2018.
- **Interconnection Rule 21** – Rule 21 Working Group One submitted its recommendations concerning urgent interconnection improvement issues to the Commission in March 2018 and Working Group Two submitted its recommendations regarding the Integration Capacity Analysis and streamlining interconnection issues in October 2018. The Commission convened regular interconnection discussion forums to facilitate greater cooperation and improvement to the interconnection process.
- **Smart Inverters** – In April 2018, the Commission approved revisions to Rule 21 by incorporating several advanced smart inverter functions and requiring Reactive Power Priority, which allows distributed generation to provide local voltage support. Reactive Power Priority became mandatory on June 26, 2018. Since August 2018, the Smart Inverter Working Group (SIWG) has met weekly to discuss the implementation of smart inverter communications requirements and other advanced functions, which will allow the grid to support additional distributed generation while contributing to grid stability.
- **Energy Storage** – The Commission approved a record setting amount of energy storage: 905.5 MW in 2018. To date the Commission has approved procurement of more than 1.6 gigawatts of new storage capacity, of which 410 MWs is online and operational, or about 26 percent of total approved storage capacity. Collectively the IOUs have procured more than the 1,325 MW target set by Assembly Bill (AB) 2514 (Skinner, Chapter 469, Statutes of 2010)[7]. By the end of 2018,

[6] See the following link for the text of D.18-03-023: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF.

[7] For the full text of AB 2514, please see the following link: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514.

San Diego Gas & Electric (SDG&E) met its 165 MW share of that requirement. Pacific Gas & Electric and Electric (PG&E) requires 39 MW in the customer domain[8] and SCE needs 139 MW in the transmission domain to fulfil their respective 580 MW shares of the target. The Commission approved 567.5 MW of storage proposed by PG&E to replace more expensive natural gas contracts representing the largest battery storage projects approved in the world. The Commission adopted a joint CPUC and California Independent System Operator (CAISO) staff proposal with a framework for multiple use applications (MUA) for energy storage in Decision (D.)18-01-003.[9] The MUA framework advances the ability of energy storage to provide more economic value by providing multiple services.

- **Plug-In Electric Vehicle Integration** – As part of implementing Senate Bill (SB) 350 (De León, Chapter 547, Statutes of 2015)[10], in 2018 the CPUC approved utility programs and pilots at all three investor-owned utilities with a combined budget of more than $748 million for pilot-scale vehicle-grid integration and larger-scale transportation electrification infrastructure investment. The CPUC is currently considering another $1 billion in utility proposals for additional transportation electrification investment programs.
- **Demand Response (DR)** –The IOUs integrated their supply-side DR programs into the CAISO wholesale market. The Commission allocated budgets for the IOUs to run DR pilots in transmission-constrained local capacity areas, including in disadvantaged communities. Several contracts were approved by the Commission for market-integrated DR to provide long-term capacity in locally-constrained areas. The IOUs procured 167 MW of competitive supply-side DR from third parties for delivery in 2019 under the Demand Response Auction Mechanism pilot (DRAM). The Commission implemented the "prohibited resources policy" which prohibits the use of customer-owned fossil fuel resources during demand response events, effective January 1, 2019.

[8] The customer domain refers to the customer's side of the meter (also known as behind-the-meter), rather than the utility's side in the distribution grid.
[9] For the full text of D.18-01-003 see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M206/K462/206462341.pdf.
[10] Please see the following link for the SB 350 Bill text: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

2. Introduction

2.1. What is the Smart Grid?

The Smart Grid,[11] as defined in the State of California by Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009)[12], is a fundamental change in the existing electricity infrastructure that utilizes advances in technology to create a safer, greener, more efficient, and more reliable electricity supply. The objectives in California, per SB 17 and Pub. Util. Code § 8360, are to promote:

- Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid;
- Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security;
- Deployment and integration of cost-effective distributed resources and generation including renewable resources;
- Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources;
- Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation;
- Integration of cost-effective smart appliances and consumer devices;
- Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in-electric and hybrid-electric vehicles, and thermal-storage air conditioning;
- Development of functions that provide consumers with timely information and control options;

[11] Per the IEEE (Institute of Electrical and Electronics Engineers), Smart Grid refers to the use of digital communications and control technology and new energy sources, generation models, and adherence to cross-jurisdictional regulatory structures to provide an objective collaboration, integration, and interoperability between computational and control systems, generation, transmission, distribution, customer, operations, markets, and service providers.

[12] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.

- Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; and
- Identification and lowering of unreasonable or unnecessary barriers to adoption of Smart Grid technologies, practices, and services.

2.2. California's Evolution to Grid Modernization

The CPUC has worked with the California IOUs and the Legislature on numerous fronts throughout 2018 to advance grid modernization. The resulting initiatives are oriented towards making the grid in California smarter, safer, and better able to accommodate higher penetrations of DERs, while reducing carbon emissions and improving reliability and resiliency. Recent grid modernization efforts have built upon smart meter[13] deployment, cost reductions in digital control and communications technology, power electronics, and advanced automation technologies that improve customer reliability and grid resilience.[14] The accelerating adoption of customer-side intermittent renewable generation, primarily solar photovoltaic (PV) systems, has produced new operational challenges and opportunities for the grid, which is driving the current need for IOU investment in Smart Grid technologies. Modernizing grid infrastructure, such that it serves as a beneficial platform rather than an impediment for customer adoption of DERs, is becoming a priority for the CPUC and the IOUs so that DERs can be interconnected to the grid in a "plug-and-play" manner.[15]

A planned approach to increase Smart Grid investments is required to increase grid reliability and to reduce safety risk in light of increasing customer adoption of DERs and traditional distribution investment deferral by DERs. The Distribution Resources Plan proceeding (R.14-08-013)[16] currently

[13] Smart meter refers to modern electrical meters that can transmit customer energy consumption information directly to the utility through its cellular network on a frequent schedule, so the utility does not need to send a person to obtain this information.

[14] Reliability is measured in number of outages and outage duration. IEEE Standard 1366 defines the following reliability metrics: Customer Average Interruption Duration Index (CAIDI), System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI).

[15] Creating a distribution grid that is "plug-and-play" involves dramatically streamlining and simplifying the processes for interconnecting to the distribution grid to create a system where high penetrations of DER can be integrated seamlessly.

[16] Please see the following link to the R.14-08-013 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf.

underway will guide new Smart Grid investment requests in future general rate cases (GRCs)[17] to meet these safety and reliability challenges.[18] The DRPs require the IOUs to begin planning and investing in the distribution system in a way that will enable higher levels of DER adoption than traditional grid planning processes have previously allowed. DERs have the potential to improve reliability and resiliency, particularly for essential emergency-response and disaster-recovery services.

The CPUC is working diligently to address all aspects of creating a modern grid for California. The DER Action Plan serves as a roadmap for decision-makers, staff, and stakeholders working in support of California's DER future in order to facilitate proactive, coordinated, and forward-thinking development of DER-related policy.

2.2.1. Deployment Plan Background

The Commission adopted several Decisions to further the state policy of Grid Modernization through implementation of the Smart Grid Proceeding (R.08-12-009)[19], including establishing that the IOUs file Smart Grid Deployment Plans (Annual Reports) annually. The three IOUs filed their initial Deployment Plans on July 1, 2011, as required by SB 17.[20] The Deployment Plans were approved by the Commission in D.13-07-024[21] on July 25, 2013. This approval cleared the way for implementation of the deployment plans as part of each IOU's GRC. Furthermore, D.13-07-024[22] adopted template criteria for the Smart Grid Annual Reports that the IOUs are required to file annually to demonstrate progress on Smart Grid deployment.

Through succeeding Decisions, the Smart Grid Proceeding ordered the Utilities to:

- Deploy smart meters and provide downloadable usage data to customers and authorized third parties, referred to as Customer Data Access (CDA);
- File Smart Grid Deployment Plans and to set the requirements for what the plans must address;

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[17] General Rate Cases are regulatory proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes for a given IOU.

[18] Pursuant to P.U. Code § 769, CPUC Rulemaking (R.) 14-08-013 is considering the IOUs' DRPs.

[19] Please see the following link to the R.08-12-009 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/95608.PDF.

[20] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.

[21] Please see the following link for the full text of D.13-07-024: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M075/K390/75390046.PDF.

[22] Please see the following link for the full text of D.13-07-024: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M075/K390/75390046.PDF.

- Protect the privacy and security of customer data generated by smart meters;
- Provide Home Area Networks (HAN) capability on the smart meters;
- Adopt metrics to measure the effectiveness of smart grid investments; and
- Convene an Energy Data Access Committee to determine ongoing access policies and issues.

In 2014, the Commission closed the Smart Grid Proceeding R.08-12-009[23], and ordered the IOUs' Smart Grid Deployment Plans to include the following eight elements:[24]

1. Smart Grid Vision Statement
2. Deployment Baseline
3. Smart Grid Strategy
4. Grid Security and Cyber Security Strategy
5. Smart Grid Roadmap
6. Cost Estimates
7. Benefits Estimates
8. Metrics

The IOUs filed their 2018 Smart Grid Annual Reports in October 2018.[25]

2.2.2. Smart Grid Costs and Benefits

The three IOUs are required to report on Smart Grid program costs and associated benefits. The costs and benefits shown in Table 1 reflect the reporting period for the IOUs' Smart Grid Annual Reports, which covers fiscal year 2017-2018[26]. Costs are calculated as the sum of all the Smart Grid programs and investments implemented by each IOU. Benefits are calculated as a sum of avoided cost of utility operations, including environmental, customer service, and Transmission & Distribution (T&D) costs, as

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[23] Please see the following link to the R.08-12-009 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/95608.PDF.

[24] Decision (D).14-12-004.

[25] The 2018 annual reports, as well prior annual reports, can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

[26] The IOUs were ordered to report data in alignment with the State's Fiscal Year which corresponds with July 1, 2017 to June 30, 2018.

well as reliability benefits, physical and cybersecurity benefits, and demand response savings realized in the fiscal year.[27] Each IOU has a different approach to calculating the Smart Grid costs and benefits. The data presented in Table 1 is shown as it was reported to the CPUC by the IOUs. This data is not suitable for direct comparison between the IOUs as they rely on different methodologies for estimating benefits. See Section 4.1 for additional detail. This data has not been vetted by the CPUC and we cannot attest to its accuracy.[28]

Table 1 IOU Costs and Benefits for Fiscal Year July 1, 2017 through June 30, 2018

IOU	Smart Grid Costs ($Millions)	Smart Grid Benefits ($Millions)	Avoided Outage Minutes
PG&E	$195.67[29]	$197	72.2 Million
SDG&E	$95.92	$109.07	3.4 Million
SCE	$77.98	$709.10[30]	219 Million

2.2.3. Ongoing Commitment to Improving Safety and Reliability

The CPUC is committed to maintaining and improving the safety, reliability and economic value of the electric supply, as well as to reducing the environmental impact of electricity production, transmission and distribution.

Pursuant to the goals of Assembly Bill 66 (Muratsuchi, Chapter 578, Statutes of 2013)[31] which directed the IOUs to improve electric system reliability through greater accountability and enhanced

[27] Benefits may include those accrued from previously completed projects and does not include all of the benefits that may be realized over the lifetime of the projects. Some Smart Grid projects may not have direct benefits but may enable other programs or technologies that will provide benefits in the future.

[28] In past GRCs the calculation of reliability benefits has been reviewed in some utilities' GRCs, but for the purpose of this report, this data is included as utilities reported it to the Commission and has not been vetted.

[29] Of this total, $87.1 million of the costs incurred this past reporting year is represented by the cumulative costs of one distribution automation and reliability project (Distribution Substation SCADA Program), and one transmission automation and reliability project (Modular Protection Automation and Control Installation Program).

[30] According to SCE, its reliability benefits are driven by its distribution automation program which was deployed two decades ago and continues to accrue benefits. In 2018, SCE estimated that its distribution automation technologies allowed SCE to avoid 219 million customer outage minutes. SCE updated its Value of Service (VOS) estimates, which calculate the cost of outages, and assigned a value of $2.91 per customer minute of interruption (CMI). By multiplying $2.91 per CMI and 219 million customer outage minutes, SCE estimated a savings of $638 million from avoided outage minutes which represents 90% of the total $709.1 million benefits SCE reported. (SCE Smart Grid Deployment Plan Annual Report, p.8). The CPUC cannot attest to the accuracy of SCE's VOS or avoided outage minutes estimates.

[31] For the full text of AB 66, please see the following link: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB66.

reporting, the CPUC issued a Decision in January 2016[32] that required reliability reporting on a more local basis by the IOUs. The IOUs were also directed to report on top one percent of their worst-performing circuits and to annually detail their investment plans for mitigating these reliability deficiency issues. Several Smart Grid technologies deployed by the Utilities, such as Geographic Information Systems (GIS) and Outage Management Systems (OMS), are expected to be deployed to mitigate reliability concerns and to automate and improve outage detection while improving reporting.

As the result of the CPUC's commitment to making safety an integral consideration in all of its proceedings, the Utilities in Fiscal Year 2017-2018 refined their safety risk assessments in their GRCs. By identifying, prioritizing, and offering mitigations for their top safety and operational risks, the Utilities are providing the Commission with a stronger rationale for considering proposed GRC investments in infrastructure upgrades, improved training, and safer operations. In their GRCs, the IOUs have identified physical and cyber security vulnerabilities to be among the utility facilities' top risks. Increasingly, mitigation proposals involve new Smart Grid technologies that enhance safety, reliability, and resiliency and to improve monitoring of grid and pipeline operations and distributed energy resources.

The CPUC also focuses on resiliency. Unlike reliability, which is well-defined with specific quantitative metrics (see Footnote 14 on page 5), resiliency is an emerging Smart Grid attribute. Resiliency can be characterized as both the ability of the system to resist failure, reduce the magnitude and/or duration of events that cause outages, and to recover from these events. Improving the ability of the system to restore operations fully from a high stress situation or event is one of the objectives of many Smart Grid initiatives. Grid modernization initiatives generally enable the utility to develop situational awareness that anticipates problems using automated fault location and smart meters. Such information and technologies contribute to maintaining a more resilient grid by reducing the frequency and duration of outages and enabling microgrids to operate in island mode.[33]

[32] D.16-01-008 in R.14-12-014. See the following link for the full text of D.16-01-008 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M157/K724/157724560.PDF.

[33] Island mode refers to when a circuit or microgrid operates in isolation from the distribution grid and can continue to serve power through DERs when the distribution grid experiences outages and can no longer serve the circuit or microgrid.

3. Commission Activities Related to Smart Grid in 2018

3.1. 2018 Smart Grid Activities

3.1.1 DER Action Plan

The Commission continues to implement its vision to support California's DER future to facilitate proactive, coordinated, and forward-thinking development of DER policy across inter-related Commission proceedings. The Commission's Energy and Administrative Law Judge Divisions participated in a steering committee and developed a management framework to coordinate implementation of the vision and goals of the DER Action Plan across multiple proceedings.[34] Using this framework, the Commission is on schedule to complete action elements in each of the three tracks of the DER Action Plan: (1) Rates and Tariffs; (2) Distribution Planning, Infrastructure, Interconnection and Procurement; and (3) Wholesale DER Market Integration and Interconnection.

In Track 1, Rates and Tariffs, the Commission implemented Action Item 1.3 of the DER Action Plan, in which the Commission examined fixed charges, time-of-use periods and rates, and nonresidential rate design in general rate cases. Additionally, the Commission carried out Item 1.13, which is the establishment of clear marketing, education and outreach plans that maximize customer adoption of time-varying rates.

In Track 2, Distribution Planning, Infrastructure, Interconnection and Procurement, the Commission adopted an annual distribution investment deferral process per Item 2.1.c for the IOUs to use to select opportunities for third party-owned DERs to defer or avoid traditional capital investments in the distribution system.

Finally, for Track 3, Wholesale DER Market Integration and Interconnection, the Commission implemented Item 3.1, in which the Commission considered market rules and regulatory policies for DER Multi-Use Applications in order to promote the ability of storage resources to provide stacked services to the grid.

[34] See the following link to the Commission's DER Action Plan: 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.

3.1.2 Distribution Resources Plans

Pub. Util. Code §769[35] required the IOUs to file Distribution Resource Plans (DRPs) by July 1, 2015. In the IOUs' Distribution Resource Plans submitted in 2015, the Commission required the IOUs to propose contracts, tariffs or other DER procurement mechanisms to maximize the locational benefits and minimize the incremental costs of distributed resources. The Commission also required the utilities to identify additional spending necessary to integrate DERs into distribution planning and to modernize their electric grids; as well as identify the barriers to the deployment of DERs. The Commission's overarching goals of this new framework are to lower incremental cost of forecasted DERs, minimize grid impacts, reduce barriers to DER deployment, and target DER deployment to avoid or defer planned utility distribution investments. Since California's climate targets require electrification of the transportation sector by 2045, DERs play an important role in mitigating load growth on the distribution system and on transmission in load-constrained areas, which is necessary to limit the costs of meeting California's climate targets.

The Commission's DRPs align with the State's Smart Grid goals of grid modernization, which includes greater customer choice (in terms of facilitating behind-the-meter DER deployment), improved communications systems, and higher levels of automation, all of which can also accommodate two-way energy flows.[36] Many of the projects and activities envisioned as part of the DRP support a smarter, cleaner grid in which customer-sited DERs not only supply power to the customer's own load, but also to other customers on the grid.

The Commission instituted the Distribution Resources Plan Proceeding, R.14-08-013[37], to consider the IOUs' 2015 DRP Applications across the following three tracks:

Track 1: Analytical/Methodological Issues

This Track is focused on developing the methodologies for two analyses that identify optimal locations for DER deployment; the analyses were adopted in D.17-09-026[38] and implemented in 2018:

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[35] Pursuant to Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013).

[36] Traditional distribution system planning practices, in which the IOUs planned the system for one-way power flows emanating from centralized power generation, are undergoing dramatic changes as a result of the requirements of Pub. Util. Code § 769.

[37] Please see the following link to the R.14-08-013 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf.

1. **Integration Capacity Analysis (Demonstration Project A)**: The ICA determines the available hosting capacity of every distribution circuit in the IOUs' service territories to accommodate additional DERs. ICA results were first published through online maps and downloadable datasets located on the IOUs' websites at the end of 2018, and will be updated on a monthly basis.[39] The ICA will help DER developers site projects in grid locations that are less likely to trigger system upgrades; will be used by the IOUs in the annual distribution planning process to identify proactive upgrades to increase a given area's hosting capacity in light of forecasted DER adoption; and will serve as the basis for a streamlined (and potentially automated) Rule 21 interconnection process.
2. **Locational Net Benefits Analysis (Demonstration Project B)**: The LNBA will determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid traditional distribution system investments. The LNBA will be updated as part of the annual distribution planning process. LNBA results that display candidate distribution investment deferral opportunities were published in online maps and downloadable datasets as a public tool. (see footnote 39). Additionally, the IOUs will be tasked with reviewing and selecting deferral projects for solicitation. The LNBA will reflect the benefits of DER deployment, relative to traditional infrastructure. This information will then inform DER sourcing activities being determined in the Integration of Distributed Energy Resources Proceeding (R.14-10-003)[40] as well as the Integrated Resource Planning effort (R16-02-007)[41].

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[38] For the full text of D.17-09-026, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747754.PDF.

[39] Integration Capacity Analysis (ICA) and Locational Benefit Analysis (LNBA) Map can be found in the IOUs DRP Data Portals found here:

SDG&E: https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica.

PG&E: https://www.pge.com/eum/login?TYPE=100663297&REALMOID=06-000d5ced-207d-1b59-a63a-7f320a31909d&GUID=&SMAUTHREASON=0&METHOD=GET&SMAGENTNAME=-SM-www%2epge%2ecom&TARGET=-SM-https%3a%2f%2fwww%2epge%2ecom%2fb2b%2fdistribution--resource--planning%2fintegration--capacity--map%2eshtml.

SCE: https://ltmdrpep.sce.com/drpep/.

[40] For the full text of the R.14-10-003 Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M116/K116/116116537.PDF.

[41] For the full text of the R.16-02-007 Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K663/158663325.PDF.

Track 2: Demonstration (Demos) and Deployment Projects

Track 2 of the DRP required the IOUs to implement Demonstration and Deployment Projects that aim to prove the IOUs' ability to plan and operate the distribution system to manage increasingly higher DER penetrations including:

1. **Demo C**: Source DER(s) to defer a traditional infrastructure investment and provide net benefits. This project is intended to validate the ability of DERs to defer or avoid investments in traditional distribution infrastructure and to achieve net ratepayer benefits as estimated by the LNBA. The Commission approved this project for PG&E, SCE and SDG&E in D.17-02-007[42] and D.17-06-012[43] in 2017. In 2018, the Commission concluded the projects for PG&E and SDG&E. PG&E's and SDG&E's Demo C DER solicitations were unsuccessful because no cost-effective DER solution bids were received relative to the cost of the traditional distribution infrastructure. Regardless, the Commission gained valuable information on the type of traditional distribution infrastructure projects that can or cannot be deferred by DERs. These lessons learned are being applied in the IOUs Distribution Investment Deferral Framework (Track 3). SCE's Demo C contracts for this project are pending Commission approval. The Commission expects to review these contracts in 2019.
2. **Demo D**: Operate the system at high penetrations of DERs. This project calls for the Utilities to integrate high penetrations of DER into their distribution operations, to demonstrate the operations of multiple DERs in concert, and to coordinate operations with third parties and customers. This project was approved for PG&E and SCE in D.17-02-007[44] and D.17-06-012[45] in 2017. PG&E's Demo D DER solicitation was unsuccessful, because it did not receive cost-effective DER bids. SCE's Demo D contracts for this project are pending Commission approval. The Commission expects to review these contracts in 2019.
3. **Demo E**: Plan and operate a microgrid. This project will demonstrate a microgrid where DERs (both customer- and utility-owned) serve a significant portion of customer load and

[42] For the full text of D.17-02-007, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M176/K178/176178449.PDF.

[43] For the full text of D.17-06-012, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M190/K737/190737689.PDF.

[44] For the full text of D.17-02-007, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M176/K178/176178449.PDF.

[45] For the full text of D.17-06-012, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M190/K737/190737689.PDF.

reliability services. Furthermore, it will demonstrate the use of a DER management system (DERMS), which is a software solution that monitors, controls, and optimizes both third-party- and utility-owned DERs. The Commission approved this project for SDG&E and SCE in D.17-02-007[46] and D.17-06-012[47], respectively, in 2017. Final results for these projects are still pending.

Track 3: Policy Issues

In Track 3 of the DRP, the Commission addressed several policy questions related to incorporating new tools and forecasting methods into existing distribution system planning and investment processes which the Commission adopted in 2018:

1. **DER Growth Scenarios and Distribution Load Forecasting**: In D.18-08-004[48], the Commission considered the methodological issues for developing circuit-level forecasts of DER adoption and distribution load to inform distribution planning, as well as support process alignment with the CEC's Integrated Energy Policy Report (IEPR), IRP, Long-Term Procurement Planning (LTPP), and the CAISO's Transmission Planning Process (TPP). In August 2017, the Commission adopted assumptions for the 2017–2018 planning cycle and approved preliminary methodologies for disaggregating to the circuit level.
2. **Grid Modernization Investment Framework**: In D.18-03-023[49], the Commission adopted a framework for identifying and evaluating which utility investments in grid modernization are necessary to integrate cost-effective DERs into distribution planning, and which will also yield net benefits to ratepayers. With the expansion of DERs, many new technologies have emerged that work to integrate DERs into grid planning and operations. If the Commission does not carefully evaluate grid modernization technologies for cost reasonableness, the cost to ratepayers for widespread adoption of all these technologies could outweigh the benefits they provide. The Commission needs a decision-making framework that will identify the necessary investments to the distribution grid that will yield net ratepayer benefits while

[46] For the full text of D.17-02-007, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M176/K178/176178449.PDF.
[47] For the full text of D.17-06-012, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M190/K737/190737689.PDF.
[48] See the following link for the text of D.18-08-004: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M221/K552/221552166.PDF.
[49] See the following link for the text of D.18-03-023: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF.

supporting a modern grid that supports high penetrations of DERs and maintains safety and reliability.

3. **Distribution Investment Deferral Framework**: In D.18-08-004[50], the Commission adopted a planning framework for identifying, evaluating, and selecting opportunities for DERs to defer or avoid traditional distribution investments and to produce net ratepayer benefits. Process alignment between the IOU's distribution planning process, DER procurement, and the GRC process is achieved in the Deferral Framework. The IOUs implemented the framework in 2018 and recommended a portfolio of distribution deferral projects that will be put out for competitive solicitation in early 2019.

3.1.3 Integrated Distributed Energy Resources

Since 2007, the CPUC has sought to integrate DERs through utility program offerings (e.g. Energy Efficiency, Demand Response) and more recently, through the Integrated Distributed Energy Resources (IDER) Proceeding R.14-10-003.[51] The Commission's intent is to integrate these resources and technologies in order to reduce greenhouse gas (GHG) emissions and to increase ratepayer benefits by displacing "wires" solutions; i.e., traditional utility planned capital investments.

In December 2016, the Commission issued Decision (D.)16-12-036[52] to address the Competitive Solicitation Framework and Regulatory Incentive Pilot. This decision adopted a technology neutral competitive solicitation framework for DERs that can be deployed to defer traditional distribution infrastructure build outs and established a regulatory process to oversee these solicitations. D.16-12-036 authorized a pilot to test a regulatory incentive mechanism through which a utility can earn a four percent pre-tax incentive on annual payments to DERs. D.16-12-036 required each utility to select at least one deferral project for the pilot but encouraged the utility to select up to three additional projects to test the incentive mechanism. Additionally, D.16-12-036 specified seven steps related to pursuing the incentive pilot, including forming a Distribution Planning Advisory Group (DPAG) to engage stakeholders with reviewing candidate deferral opportunities. The DPAG advised and consulted with the Utilities regarding

[50] See the following link for the text of D.18-08-004: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M221/K552/221552166.PDF.
[51] For the full text of the IDER Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M116/K116/116116537.PDF.
[52] For the full text of D.16-12-036, please the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF.

the process for considering proposed distribution deferral pilot projects, contingency plans, proposed counting method, and valuation components for the Incentive Pilot.

In December 2017, the Commission adopted Resolution E-4889[53] ordering SCE and SDG&E to move forward with their DER solicitations. The Commission also granted PG&E's request for an extension to start its solicitation process due to the 2017 North Bay fires. Following the completion of the solicitation process in 2019, the Commission, with the DPAG, will evaluate the solicitation process and reconvene the Competitive Solicitation Framework Working Group to develop a technology neutral solicitation document to be used for future DER solicitations.

Pursuant to D.16-12-036 and Res. E-4889, SCE and SDG&E began their solicitation process in January 2018. SDG&E selected one project, Circuits 303 and 783 in Carlsbad, for their IDER Pilot. It considered integrated hybrid resource types to meet the total required distribution capacity for each circuit project replacement or deferral with deliveries beginning as early as September 1, 2019. SDG&E completed its solicitation on March 20, 2018 and did not receive any cost-effective bids.

SCE selected two substation upgrade projects, the Eisenhower Project in Cathedral City and the Newbury Project in Thousand Oaks for their IDER Pilot. SCE considered integrated hybrid resource types that would increase capacity for these two projects. SCE completed its solicitation in May 2018. On November 5, 2018, the Commission approved four in-front-of-the-meter energy storage contracts for Distribution Deferral and Resource Adequacy, totaling 9.5 MW that will defer the substation upgrades for 9.5 years. These projects are the first successful cost effective IDER pilot projects that would defer capital investment, and the first projects which apply the Commission approved Multi-Use-Application rules representing added value stacking for ratepayers by procuring multiple services.

In October 2018, the Commission adopted Resolution E-4956[54] ordering PG&E to start its IDER solicitation process. PG&E is expected to complete its IDER RFO solicitation in the first quarter of 2019.

3.1.4 Interconnection Rule 21

The Rule 21 tariff sets interconnection, operating, and metering requirements for generation facilities to be connected to a utility’s distribution system in order to maintain safety and reliability of the

[53] For more information, see Resolution E-4889: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K961/201961781.PDF.

[54] Please see the following link for the full text of Resolution E-4956: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M235/K815/235815737.PDF.

distribution and transmission systems. Barriers to the deployment of distributed resources are addressed in the Commission's Interconnection Rulemaking, R.17-07-007[55]. In 2018, the Interconnection Rulemaking considered policy and programmatic changes to streamline the interconnection process. The March 2018 Working Group One Report[56] addressed urgent interconnection issues. The October 2018 Working Group Two Report[57] primarily leverages work on the Integration Capacity Analysis from the utility Distribution Resource Plans Proceeding R.14-08-013[58] to further streamline the Fast Track process[59] in Rule 21. The Commission will consider the Working Groups' recommendations in forthcoming decisions.

The Commission will also continue implementation of Assembly Bill 2861 (Ting, Chapter 672, Statutes of 2016)[60], which authorizes the CPUC to establish an expedited interconnection dispute resolution process that strives for a binding resolution of an interconnection dispute within 60 days.

3.1.5 Smart Inverters

Inverters convert Direct Current (DC) to Alternative Current (AC) power and hence are essential for interconnecting various DERs, including solar PV systems (which produce DC power), to the grid. Smart inverters provide capabilities beyond those of a standard inverter—autonomous response to voltage and frequency conditions, safety features, and communications capabilities—and are one of the foundational building blocks of the Smart Grid. Smart inverters' primary benefit is to increase the capacity of the distribution system to accommodate higher penetrations of DERs. Smart Inverters accomplish this by mitigating some of the grid impacts of intermittent variable resources and enhancing these same DERs' ability to serve as grid assets. They can also improve operation of the grid through advanced communications and control. Through the direction of the Commission, the Smart Inverter Working

[55] For the full text of the R.17-07-007 Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K079/192079467.PDF.

[56] The R.17-07-007 Working Group One Report is accessible through the following link: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/Infrastructure/RDI/itcn/R1707007WorkingGroupOneFinalReport.pdf.

[57] The R.17-07-007 Working Group two Report is can be found on in the following webpage: http://www.cpuc.ca.gov/General.aspx?id=6442455170.

[58] Please see the following link to the R.14-08-013 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf.

[59] The Fast Track process is a streamlined review process that is based on multiple evaluation screens for interconnecting net energy metering, non-export, and small exporting facilities.

[60] For the full text of AB 2861, please see the following link: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB2861.

Group (SIWG) has developed inverter functionality recommendations that are being incorporated into the Electric Rule 21 tariffs. These recommendations are grouped into three phases: Phase 1 describes seven autonomous smart inverter functions, Phase 2 defines smart inverter communications requirements, and Phase 3 outlines eight advanced smart inverter functions.

As of September 9, 2017, the IOUs incorporated seven autonomous Phase 1 smart inverter functions into their Rule 21 tariffs and made these Phase 1 functions mandatory for all inverter-based DERs interconnecting under Rule 21, pursuant to Commission Decision (D.)14-12-035[61] and R.11-09-011.[62] The Phase 2 Smart Inverter communications requirements were added to Rule 21 in April 2017 and it is expected that these capabilities will become mandatory in 2019. Once these requirements are adopted, all inverter-based generation interconnecting under Rule 21 will be capable of communication and Institute of Electrical and Electronics Engineers (IEEE) 2030.5[63] will serve as the default protocol used by IOUs to communicate to either individual DERs, energy management systems, or DER aggregators. These communications, when operationalized, will increase utility visibility into grid conditions and allow DERs to respond to shifting grid needs.

In April 2018, the Commission approved revisions to Rule 21 that incorporate smart inverter Phase 3 advanced functions. The Commission also adopted Reactive Power Priority, which is a powerful tool for preventing and mitigating voltage rise on the distribution system. Reactive Power Priority became mandatory in June 2018. Since August, the Smart Inverter Working Group (SIWG) has met weekly to discuss the implementation of smart inverter Phase 2 communications requirements as well as Phase 3 advanced functions such as "Scheduling Power Values and Modes." Once implemented, these functions will increase the amount of DER generation that the grid can accommodate without infrastructure upgrades and will increase grid safety and stability.

The Phase 2 communications requirements and Phase 3 advanced functions represent higher levels of DER dispatch and control capabilities which are necessary for leveraging DERs for grid operations. The inclusion of these requirements in Rule 21 represents a critical step towards the attainment of the CPUC DER Action Plan goal 2.13 to "fully operationalize advanced (beyond Phase 1) smart inverter functionalities by 2020 to enhance the integration of DERs into the grid."

[61] For the full text of R.14-12-035, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF.

[62] For the full text of R.11-09-011, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/144161.PDF.

[63] Also known as Smart Energy Profile (SEP) 2.0 Application Protocol Standard.

3.1.6 Energy Storage

The Commission's energy storage procurement policy was formulated with three primary goals:

1) Grid optimization, including peak reduction, contribution to reliability needs, or deferral of transmission and distribution upgrade investments;
2) Integration of renewable energy; and
3) GHG reductions in support of state targets.

In response to AB 2514[64], the Commission established energy storage targets in 2013 of 1,325 MW to be procured by 2020 and operational by 2024. In 2018, the Commission approved a record setting amount of energy storage: 905.5 MW. To date the Commission has approved procurement of more than 1.6 gigawatts of new storage capacity to be built in the state, of which 410 MWs are online and operational, which is about 26 percent of total approved storage capacity. The AB 2514[65] mandate is to be procured in three distinct grid domain targets with some flexibility between the grid domain targets. Cumulatively the utilities have exceeded the 1,325 MW target, but SCE and PG&E still need additional domain-specific procurement to complete the mandate.[66] See Table 2 below for more detail including the grid domains and targets.

[64] For the full text of AB 2514, please see the following link: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514.

[65] For the full text of AB 2514, please see the following link: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514.

[66] SCE and PG&E are together 178 MW short of meeting the AB 2514 mandate. PG&E requires 39 MW on the customer domain and SCE needs 139 MW on the transmission domain. SDG&E has met their target.

Table 2. IOU Progress Towards the AB 2514 Energy Storage Target (MW)

	Grid Domains	Total Storage Procurement per AB 2514 Required by 2020	AB 2514 Driven Storage Procurement as of 2018	Storage Procurement through other CPUC Proceedings as of 2018	Total Storage Procurement Through all Eligible Proceedings as of 2018	Total Storage Procurement Adjusted per AB 2514 Rules as of 2018	Excess/Deficiency Relative to the Total AB 2514 Target
PG&E	Transmission	310	135	557	692	544	234
	Distribution	185	36	0	36	185	0
	Customer-Side	85	36	10	46	46	-39
SCE	Transmission	310	0	120	120	171	-139
	Distribution	185	27	112	134	185	0
	Customer-Side	85	100	205	306	221	136
SDG&E	Transmission	80	-	110	110	80	0
	Distribution	55	-	57	57	56	1
	Customer-Side	30	-	29	39	30	0
	IOU Total	**1,325**	**334**	**1,200**	**1,540**	**1,518**	

Energy storage has been procured to meet local capacity requirements and is a focus of distribution planning, deferral, and other services. Thus, energy storage is emerging as a crucial backbone of the Smart Grid. Since the beginning of the California Storage Framework, storage contract prices have declined between 40% and 50%. The Commission implementing Assembly Bill 2868 (Gatto, Chapter 681, Statutes of 2016)[67] which allows for the procurement of up to 500 additional MWs of distribution-connected energy storage, with up to 25% behind the utility meter.

Energy Division and CAISO developed a joint framework of rules to govern multiple use applications (MUAs) for storage, which was adopted by the Commission in January 2018 with D.18-01-003[68]. The MUAs will allow energy storage devices to provide multiple grid benefits market services, and to realize their full economic potential. The framework included eleven rules to guide development of MUAs. D.18-01-003 required the formation of a working group to develop additional recommendations on a defined set of topics. The working group met multiple times in 2018 and submitted its report to the Commission on August 9, 2018.

The Commission approved SCE and PG&E's 2016 RFO energy storage procurement on October 11, 2018, which resulted in 175 MWs of new storage capacity – 135 MWs in the transmission domain; 30

[67] For the full text of AB 2868, please see the following link: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868.

[68] For the full text of D.18-01-003 see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M206/K462/206462341.pdf.

MWs in the distribution domain and 10 MWs behind the meter, in the customer domain. One 20 MW distribution interconnected project proposed by PG&E will be owned by the utility and will provide both distribution deferral benefits as well as resource adequacy and wholesale market services, making it the first MUA project approved by the Commission. The Commission authorized this procurement to count toward AB 2514[69] targets.

Additionally, the Commission approved SCE's second Preferred Resources Pilot (PRP) RFO on July 12, 2018, which included 60 MW of storage in distribution domain and 10 MW of solar plus storage on the customer side.[70] SCE will use this approved procurement in addition to earlier procured DERs from the first PRP RFO to offset increasing customer demand for electricity in central Orange County that is partly due to the closure of the San Onofre Nuclear Generating Station (SONGS) and the impending retirement of nearby ocean-cooled power plants.

On November 8, 2018, the Commission in Resolution E-4949 approved PG&E's request to procure 567.5 MW of lithium ion batteries in the South Bay-Moss Landing subarea to meet local reliability needs[71]. The four projects are estimated to yield $233 million in ratepayer benefits over 10 years and will likely yield more benefits given that most of the approved storage has a 15 to 20-year lifespan.

In 2018, SDG&E met its obligations under AB 2514[72] to procure 165 MWs of energy storage, after the Commission approved its remaining 85 MW of storage needed to partially replace the capacity of SONGS which retired in 2012. In 2013 and again in 2014, the Commission required SDG&E and SCE to conduct RFOs for energy storage and preferred resources to replace the capacity of SONGS and the planned retirement of once through cooled plants

[69] For the full text of AB 2514, please see the following link: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514.

[70] The Commission in D.18-07-024 approved 125 MW of DERs in total as it also approved 55 MW of demand response.

[71] Of the 567.5 MW of energy storage, there will be one 182.5 MW utility-owned project on the transmission side that would likely be the largest project in the world when completed, and 385 MW of third party owned energy storage comprised of 3 different projects (all on the transmission side except for one 10 MW project on the customer side).

[72] For the full text of AB 2514, please see the following link: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514.

3.1.7 Plug-In Electric Vehicle Integration

The State of California aims to have 5 million light-duty[73] zero emission vehicles on the road by 2030 and have 250,000 electric vehicle charging stations operational by 2025 in order to help reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030 and help achieve carbon neutrality by 2045.[74] To date, there are approximately 491,000 light-duty zero emission vehicles on the road in California. Beginning with the Smart Grid Proceeding R.08-12-009[75], the Commission began exploring the potential for plug-in electric vehicles (PEVs) to interact with an increasingly modernized grid. The CPUC's activities related to PEVs are broadly categorized into four areas:

1) Charging infrastructure deployment
2) Rates
3) Vehicle-grid integration
4) Rebates and incentives

In 2016, the CPUC issued Decisions authorizing SDG&E,[76] SCE,[77] and PG&E[78] to deploy charging infrastructure to support PEVs. In 2017, with total budgets of $197 million, the three IOUs continued or launched their pilots to install the necessary infrastructure to support up to 12,500 charging stations. The IOUs are installing charging infrastructure in multi-unit dwellings, workplaces, and some public locations. The IOUs are using various load management techniques, including rate design and demand response programs, to ensure the new vehicle load is beneficial to the grid.

A 2012 settlement between the CPUC and NRG directed NRG to spend $102.5 million to deploy infrastructure to support the same location sectors as the IOU programs above, as well as public DC fast charging and pilot programs to support research and development (R&D) and underserved communities.[79] In addition to some of the load management strategies described above, the NRG Settlement is also testing vehicle-to-grid technologies and energy storage integration as load management strategies.

[73] Light-duty refers to passenger vehicles (cars and light trucks) and all other vehicles under 8,500 pounds.
[74] See Governor Edmund (Jerry) Brown's Executive Order B-55-18 to Achieve Carbon Neutrality for more information https://www.gov.ca.gov/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.
[75] Please see the following link to the R.08-12-009 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/95608.PDF.
[76] For more information see D.16-01-045.
[77] See D.16-01-023 for more information.
[78] See D.16-12-065 for more information.
[79] For more information about the CPUC/NRG settlement agreement, please see the following link: http://www.cpuc.ca.gov/General.aspx?id=5936.

PG&E, SCE, SDG&E and Liberty Utilities each continue to offer EV time-of-use energy rates for residential customers to encourage off-peak EV charging. SDG&E also offers a dynamic EV rate for those that use charging infrastructure deployed in the infrastructure pilot described above.[80] SCE and Liberty have commercial time-of-use rates specifically for commercial EV customers. In 2018 the Commission also approved three new commercial EV rates for SCE customers, a Public Grid Integrated Rate for SDG&E to use at DC fast charging stations the utility owns, [81] and an EV TOU Pilot Rate for Bear Valley customers. In November of 2018, PG&E submitted an application to establish a new commercial EV rate, which the Commission will be evaluating in 2019.

The CPUC, along with other state agencies, is developing policies that support Vehicle-Grid Integration (VGI), a framework for utilizing the flexible charging and discharging capabilities of PEVs to provide grid services. At the end of 2018, the Commission incorporated a staff report into the procedural record of the new Order Instituting Rulemaking (OIR) regarding Transportation Electrification. This staff report summarizes the findings and recommendations of a 2017 stakeholder working group on communication protocols that could enable VGI to scale. Additionally, Energy Division staff is collaborating with the other state agencies to update the 2014 VGI Roadmap.[82]

In 2018, the CPUC authorized three Transportation Electrification decisions pursuant to SB 350.[83] The CPUC authorized the three large IOUs to spend a combined $42 million on 15 pilot projects, [84] and an additional $738 million to support large-scale investments to support the electrification of the medium- and heavy-duty sectors in PG&E and SCE service territories and light-duty sectors in SDG&E and PG&E service territories. [85] The CPUC also authorized the three small IOUs to spend up to $7.33 million on eight transportation electrification programs and test a new EV rate, mentioned above.[86]

[80] In SDG&E's dynamic rate, prices change in response to expected hourly grid conditions.

[81] Through this rate, SDG&E directly passes the TOU rate signals through to the driver or customer to encourage off-peak charging.

[82] Please see the following link for the VGI Roadmap: https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf.

[83] Please see the following link for the SB 350 Bill text: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

[84] For more information see D.18-01-024 which is available through the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K670/204670548.PDF.

[85] See D.18-05-040 for more information.

[86] See D.18-09-034 for more information.

In December 2018, the Commission issued a new OIR regarding Transportation Electrification, which directs the utilities to develop EV rates that are affordable and beneficial to the grid and directs staff to develop a framework to guide future IOU investments in Transportation Electrification.

3.1.8 Demand Response

In D.16-09-056,[87] the Commission adopted the following goal for the IOU's demand response (DR) programs: "Commission-regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost."[88] The IOUs implemented the first year of five-year DR portfolio adopted in D.17-12-003,[89] including the first-time integration of all supply-side DR programs into the CAISO wholesale market. The Commission allocated $2.5M budget for IOUs to develop pilots to help shape policy on targeting demand response in transmission constrained local capacity areas and disadvantaged communities.

The Commission approved the first market-integrated DR contract based primarily on load reductions by residential customers to provide about 4.5 MW in long term capacity in the San Diego locally-constrained area. The Commission approved contracts for 45 MW of market-integrated, behind-the-meter, storage-based DR, including first time use of batteries deployed in residential homes, to provide long term capacity in one of SCE's locally-constrained areas. In addition, the Commission approved Resolution E-4949 in November 2018 which included a contract for 10 MW of market-integrated, behind-the-meter, storage-based DR to provide long term capacity in one of PG&E's locally-constrained areas.

[87] For the full text of D.16-09-056, see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K725/167725665.PDF.

[88] D.16-09-056 also specified principles for DR to be (1) flexible and reliable to support renewable integration and emission reductions, (2) evolve to complement the continuous changing needs of the grid, (3) DR customers shall have the right to provide demand response through a service provider of their choice and Utilities shall support their choice by eliminating barriers to data access, (4) implemented in coordination with rate design, (5) DR process shall be transparent, (6) 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. For more information, see D.16-09-056.

[89] For the full text of D.17-12-003, see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K275/202275258.PDF.

In D.17-10-017[90], the Commission i) adopted the Competitive Neutrality Cost Causation Principle to allow community choice aggregators (CCAs) and direct access (DA) providers to create their own DR programs in competition with Utilities DR programs, ii) established a Supply Side Working Group to develop proposals to address barriers to integration of DR into CAISO markets and a Load Shift Working Group to develop a framework for new DR models, and iii) ordered an additional Demand Response Auction Mechanism DRAM pilot 2018 auction for 2019 deliveries with an authorized budget of $13.5 million to support the development of a competitive third-party DR market .

Pursuant to the last order, the IOUs procured 167 MW of competitive DR from third parties for delivery in 2019. Per D.16-09-056, Energy Division Staff conducted an evaluation of DRAM pilots against six criteria specified by the Commission and the Energy Division released an interim report on July 24, 2018 addressing four of these questions. Energy Division Staff submitted a final report including results on the two remaining questions (related to CAISO market performance) on January 4, 2019.

The Commission issued Decision (D.)18-11-029[91] with rulings as follows:

1. Pauses consideration of DRAM pilot extension until after the DRAM evaluation is released (the evaluation was released January 4, 2019 and the Proceeding is now considering the DRAM extension).
2. Adopted a statewide handbook on the purpose, policies and rules of the utilities' Auto DR program which provides incentives to customers for automating building load reductions during DR events.
3. Confirms that Reliability based Demand Response Resource (RDRR) can be used anytime within the Warning Stage, increasing the flexibility available to CAISO for utilizing this reliability resource to potentially alleviate an imminent grid emergency condition.
4. Prioritizes third-party customers in the allocation of the megawatts under the two percent cap on RDRR.
5. Directs IOUs to conduct Pilots focused on economic benefits for disadvantaged communities.
6. Orders a stakeholder process to study whether (and how) battery controls should be included in the Auto DR incentive program.

[90] For the full text of D.17-10-017, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M198/K319/198319901.PDF.

[91] For the full text of D.18-11-029, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M248/K670/248670669.pdf.

In line with the state's focus on reducing greenhouse gas emissions, the Commission implemented a prohibition, effective January 1, 2019, of customer-owned fossil fuel generators from use during DR event and launched an associated verification mechanism.

3.1.9 Enhanced Electric Reliability Reporting

Enhanced electric reliability reporting provides an objective standard and information to foster continuous improvement of reliability issues. Pursuant to the goals of AB 66[92] which directs the IOUs to improve electric system reliability through greater accountability and enhanced reporting, the CPUC issued a Decision in January 2016 that required reliability reporting on a more local basis by the IOUs. The IOUs were also directed to report one percent of their worst-performing circuits and to annually detail their investment plans for mitigating these reliability deficiency issues. Several Smart Grid technologies deployed by the Utilities, such as Geographic Information Systems (GIS) and Outage Management Systems (OMS), are expected to be deployed to mitigate reliability concerns and to automate and improve outage detection while improving reporting.

D.16-01-008[93] in R.14-12-014 directs the Utilities to use an enhanced reliability reporting template to report reliability data to the Commission on July 15 of each year beginning in 2017.[94] Reliability data is reported at the system level as well as division or district level.[95] The 2016 Decision requires the IOUs to identify and report on their worst performing circuits based on two or three years of repeat poor performance according to quantified reliability metric. The three IOUs report one percent of their worst-performing circuits, while PacifiCorp, Liberty Utilities, and Bear Valley Electric Service report their three-, two-, and one-worst performing circuits, respectively and combine their reporting into a single report for the Commission.

The Decision also allows customers to request reliability information about their circuits via utility websites and to receive responses in a timely manner. All Utilities will conduct at least one annual public in-person town hall and webinar presentation about the information in their annual electric reliability

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[92] For the full text of AB 66, please see the following link: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB66.

[93] See the following link for the full text of D.16-01-008 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M157/K724/157724560.PDF.

[94] The Electric System Reliability Annual Reports can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4529.

[95] Electric utilities divide their service territories into either Divisions or Districts. Each Division or District consists of groups of electric circuits.

reports. Furthermore, in compliance with D.16-01-008, the electric Utilities are developing a joint proposal to consolidate different reliability-reporting requirements from Commission Decisions and General Orders into a single reporting framework.

In 2017, the IOUs reported above national median electric reliability performance based on IEEE Distribution Reliability Working Group 2018 survey results of 250 electric companies nationwide.[96] Table 3 below compares the electric reliability indices of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) with the national electric reliability indices median values.

Table 3. IOU Electric Reliability Compared to the U.S. National Median Values for 2017

Utility / Reliability Measure	National (Median)	PG&E	SCE	SDG&E
Duration per Customer (Minute/Customer)	120	90	89.99	62.66
Frequency per Customer (Event/Customer)	1.07	0.792	0.84	0.504
Duration per Event (Minute/Event)	162	113.6	106.71	124.38

Enhanced reliability reporting supports the State's grid modernization efforts by increasing transparency into the reporting metrics for reliability standards and by requiring the IOUs to publicly describe the remediation efforts they plan to take to address the worst performing circuits. The reporting will ultimately serve as an assessment tool to measure the progress in grid reliability and security improvements as indicated in SB 17[97] and Pub. Util. Code § 8360.

3.1.10 Customer Data Access

The Click-Through Authorization Process

In early 2018, the IOUs completed the first phase of the click-through authorization process, which allows customers to easily share their energy data with third-party DR providers who can use the data to help the customer optimize their DR performance.[98] Prior to the improved click-through authorization process,

[96] IEEE Distribution Reliability Working Group has solicited annual surveys of electric reliability indices since 2003 to benchmark utilities reliability performances. Calculations are based on IEEE Standard 1366-2012.

[97] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.

[98] PG&E, SDG&E and SCE completed their authorization processes in February 2018, March 2018, and April 2018 respectively.

customers would either have to fill out a paper authorization form or go through a multi-step online authorization process on the IOU's website. The new streamlined process that occurs on the IOU's website can be completed in as little as two-screens and four-clicks. Below is a diagram that describes the process (though each IOU implementation is slightly different):

Expanding the Click-Through Authorization Process

The IOUs filed applications to expand the click-through process on November 26, 2018, per Resolution E-4868 Ordering Paragraph 29. Resolution E-4868 ordered the IOUs to include in an application, proposals to:

- Expand the click-through authorization process to DER and energy management providers, which include consideration of customer protection issues and the evaluation of which data sets should be available to which providers;
- Make improvements to the click-through authorization processes;
- Improve data delivery processes;
- Offer an alternative click-through authorization process; and
- Deliver the expanded data set, within ninety seconds.

In order to develop a robust application for expanding the click-through solutions to distributed energy resource providers, in May 2018, the Commission's Energy Division worked with the Customer Data Access Committee to solicit feedback on improvements to the click-through process that will be included in the IOU applications.

Customer Choice Final Paper and Gap Analysis

The Commission published the California Customer Choice Final Paper in August 2018 that included a section on data access and customer protection.[99] The paper briefly explains the current framework for customer data privacy and authorization and asks whether additional protections are needed. The Commission also published the Customer Choice Gap Analysis in December 2018, in which Commission Staff recommended that the Commission open a new rulemaking to further explore data access issues that are not within the scope of the applications filed in November 2018 to expand the click-through

[99] Please see the following link for the California Customer Choice Final Paper: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf.

process.[100] These issues include data access for CCAs, building managers, local governments, and research institutions, as well as data quality issues.

Energy Atlas: A Geospatial Tool to Combat Climate Change

Since 2014, the CPUC has been part of a group of state and local agencies to support the development of the Energy Atlas, a geospatial analytical tool developed by UCLA's California Center for Sustainable Communities Institute of the Environment. The Energy Atlas is the largest set of disaggregated energy data in the nation, and uses energy consumption data at the building level, combined with public records, to reveal previously undetectable patterns about how people, buildings and cities use energy. The tool helps regional planners and decision makers more effectively target energy program interventions and develop policies to mitigate and prepare for climate change. Originally limited in scope to Los Angeles County, CPUC Decision (D.)18-05-041 (Ordering Paragraph 32) directs the utilities to expand the Energy Atlas to all IOU territories statewide.[101,102]

3.1.11 Conversion of Mobile Home Park Master Meters to Direct Utility Meters

The Commission's efforts to phase out master-metering and sub-metering and replace them with direct utility metering[103] will bring the benefits of smart meters to more customers and raise customer awareness of their electrical usage and costs.

The Commission adopted D.14-03-021 to implement tariffs in a three-year pilot program to convert 10 percent of electric and natural gas master-metered services at mobile home parks (MHPs) and manufactured housing communities to Utility direct service by the end of 2017.

Utilities have submitted annual status reports to the Commission for 2015 and 2016 and filed Advice Letters in 2017 to request continuation of the conversion program pursuant to Ordering Paragraph (OP)

[100] Additional information on the Customer Gap Analysis can be accessed here: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Final%20Gap%20Analysis_Choice%20Action%20Plan%2012-31-18%20Final.pdf.

[101] Please see the following link for the text of D.18-05-041: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K706/215706139.PDF.

[102] The Energy Atlas is a free, public tool that is available at http://www.energyatlas.ucla.edu/.

[103] By default, the replacement meters will be smart meters unless a customer opts out.

13 of D.14-03-021.[104] On September 28, 2017, the Commission issued Resolution E-4878[105] which authorized all currently participating electric and gas utilities to continue their Mobile Home Park Utility Upgrade Pilot Program (MHP Pilot)[106] until the earlier date of either December 31, 2019, or the issuance of a Commission Decision for the continuation, expansion or modification of the program beyond December 31, 2019. The Resolution projects a minimum of $70 million to extend the Utility Upgrade program from January 1, 2018 to December 31, 2019.

On May 7, 2018, the Commission approved Order Instituting Rulemaking R.18-04-018[107] to Evaluate the Mobile Home Park Pilot Program and to Adopt Programmatic Modifications. This rulemaking will determine if the MHP Pilot should become a permanent program beyond 2019, and if programmatic changes are needed.

3.2. Smart Grid Activities Expected in 2019 at the CPUC

Below is a list of some of the Grid Modernization and Smart Grid development projects anticipated in 2019:

- **DER Action Plan –** The Commission will continue to support the realization of the vision expressed in the CPUC DER Action Plan. The Commission will continue to implement many of the action items in 2019 as described throughout this report. The Commission expects to initiate or complete the following notable elements in 2019: the consideration of a successor tariff to net energy metering (Action 1.5), defaulting residential customers to time of use rates pursuant to R.12-06-013 (Action 1.14), adopting new interconnection rules that leverage the utilities' Integration Capacity Analyses to streamline DER interconnection processes (Action 2.11), and continuing to integrate demand response programs into wholesale markets (Actions 3.2 and 3.3).

[104] D.14-03-021 OP 13: "Any utility may file a Tier 2 Advice Letter within 45 days of the second annual status report to request continuation of the conversion program if the actual experience to that point appears to warrant continuation of the program without major modification. Among other things, the advice letter filing should specify the application period and the application process and should include a target for converting an additional number of spaces, either as a whole number or a percentage of the remaining spaces in the utility service territory potentially eligible for conversion." See the following link for the full text of D.14-03-021: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008491.PDF.

[105] Please see the following link for Resolution E-4878: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K538/196538125.PDF.

[106] The MHP Pilot program converts master meters to direct utilities meters. This increases safety and reliability as well as electric capacity of the mobile homes.

[107] For the full text of the R.18-04-018 Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M214/K124/214124247.PDF.

- **Distribution Resources Plan –** The IOUs will publish the data portal with complete dataset from the ICA, LNBA, load and DER forecasts, Grid Needs Assessment and distribution deferral opportunities by January 1, 2019, and will issue solicitations for distribution deferral projects in early 2019. The DRP proceeding will complete new methods to quantify locationally sensitive avoided transmission and distribution costs of DERs to inform a future update to the Avoided Cost Calculator which is used to determine the cost effectiveness of numerous demand side DER programs including a planned review of net energy metering (NEM) in 2019.
- **Energy Storage –** The CPUC Staff anticipates that a new rulemaking may be established to address remaining and emerging policy issues for energy storage such as greenhouse gas reductions, microgrids, and renewable integration. Additionally, Staff expects a new OIR on implementing MUA for DERs could potentially open in 2019. The IOUs will file numerous storage procurement application in 2019 for procurement related to Aliso Canyon, AB 2868[108], and local generation and transmission capacity needs. Finally, the CPUC will contract for an evaluation framework and report on the California Storage Framework achievement of storage goals.
- **Interconnection Rule 21 –** The Rule 21 Working Groups in 2019 will address: 1) planning, construction, and billing of distribution upgrade issues, 2) application processing and review issues, 3) smart inverter issues and coordination with the Integrated Distributed Energy Resources proceeding, and 4) safety and environmental issues. Phases 2 and 3 of the Rule 21 Interconnection proceeding—addressing small and multi-jurisdictional utility rates and rate-setting issues—will commence after those Working Groups finalize their recommendations.
- **Smart Inverters –** In 2019, smart inverter Phase 2 communications requirements and new advanced functions will be mandatory for all inverter-based generation interconnecting under Rule 21. Once activated, these functions could increase the amount of renewable generation that the grid can accommodate without upgrades and will contribute to grid safety and stability. Rulemaking 17-07-007 will consider operational requirements of smart inverters including rules and procedures for adjusting smart inverter advanced functions via communication controls.
- **Integrated Distributed Energy Resources (IDER) -** In early 2019, PG&E will complete its pilot for a competitive DER solicitation process. Energy Division will review and analyze the Utilities Evaluation Report on the Competitive Solicitation Process and determine the success of

[108] For the full text of AB 2868, please see the following link: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868.

the pilot. Energy Division will review each utility's technology neutral pro forma contract document which is intended to be used for future DER solicitations. The IDER proceeding will complete record development work aimed at adopting non-RFO DER sourcing mechanisms which intend to expand opportunities for cost-effective DER procurement for more near-term distribution deferral opportunities and to streamline DER procurement in general.

- **Transportation Electrification –** As a result of the OIR issued in December of 2018, the CPUC Energy Division will issue a staff proposal in mid-2019 for a Transportation Electrification Framework that identifies the priorities for future IOU investment in this space. The framework will be based on the transportation sector's ability to support the state in reaching its greenhouse gas reduction goals and air quality targets. The staff proposal will also discuss the intersection of transportation with other efforts, including demand response, integrated resource planning, and grid planning. In addition to the staff proposal, the CPUC is currently reviewing applications from the IOUs to spend another approximately $1 billion on proposed infrastructure programs. These efforts will continue into 2019.
- **Demand Response -** The Load Shift Working Group in Q1 2019 delivered a report proposing possible market-oriented products to move flexible loads to periods of high renewable generation to help integrate renewables, create savings by use of lower priced energy, and reduce greenhouse gas emissions. The Energy Division will lead a stakeholder process in the first quarter of 2019 to propose DRAM improvements to be considered by the Commission when it takes up the question of next steps for DRAM. In the spring of 2019, the Commission will lead a stakeholder process (to develop recommendations on whether (and how) battery controls should be included in the Auto DR incentive program. The Commission will conduct a new proceeding to consider which verification measures should be utilized to enforce the prohibition on the use of customer-owned fossil fuel generators during DR events.
- **Customer Data Access –** In 2019, the Commission expects that the Click-Through Authorization Process application proceeding will develop a record on improvements and expansion of the click-through process that allows customers to share their data with a third-party DER provider. The Commission may explore additional data access issues that need resolution in 2019 as part of the Customer Choice Gap Analysis for planning for customer DER adoption. Additionally, the utilities will issue a request for proposals in 2019 seeking a statewide rollout coordinator for the Energy Atlas, with work expected to begin in 2020.

- **General Rate Cases -** The Commission will review PG&E's 2019 GRC, which will include several Grid Modernization-related proposed investments. The Commission will issue a final Decision on SCE's 2017 GRC which includes significant grid modernization requests.
- **Wildfire Safety and Mitigation –** Recent devastating wildfires led to heightened interest among lawmakers, regulators, utilities, and the public in strengthening the utilities ability to reduce wildfire risk through investments in safety and grid resiliency. In 2019, the Commission is expected to issue one or more Decisions on the IOU Wildfire Mitigation Plans pursuant to Senate Bill 901 (Dodd, Chapter 626, Statutes of 2018). The Commission is also expected to rule on SCE's Grid Safety and Resiliency application which seeks over $500 million of investments in wildfire prevention and mitigation. The Commission is examining utility programs to de-energize power lines in cases of dangerous wildfire conditions that public safety in R.18-12-005[109].

4 Smart Grid Projects in California

4.1 Summary of IOU Activities in 2018

The State of California and the California IOUs continued to advance Smart Grid development initiated in 2009 pursuant to SB 17[110]. Utility activities are reported in the Smart Grid Annual Reports, which are filed by the IOUs each October, per D.10-06-047,[111] and are organized into the categories below:

- Customer Empowerment;
- Transmission and Distribution Automation/Utility Operations;
- Cyber and Physical Grid Security;
- Integrated and Cross-Cutting Systems; and
- Asset Management, Safety and Operational Efficiency.

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[109] Please see the following link for the R.18-12-005 OIR: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M251/K987/251987258.PDF.

[110] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.

[111] The names of the reports are as follows for SDG&E, SCE and PG&E respectively: "SDG&E Smart Grid Deployment Plan 2018 Annual Report", "Southern California Edison Smart Grid Annual Deployment Plan Update", and "Pacific Gas and Electric Company Smart Grid Annual Report – 2018." All these reports can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

The IOUs are required to report the monetary value of benefits derived from Smart Grid activities. While the methodology for calculating benefits among the three Utilities has some variability, they all calculate reliability benefits as the largest benefit of Smart Grid activities. In prior years each Utility estimated their reliability benefits using a Value-of-Service reliability model developed by the Lawrence Berkeley National Laboratory (LBNL). This model is used to determine reliability benefits by monetizing reductions in customer minutes of interruption that are achieved through fault location isolation and service restoration (FLISR) and other distribution automation technologies.[112] While the IOU's utilize the same Value of Service Reliability model as the foundation for estimating their reliability benefits, their estimated value of service measured by dollars per customer minute of interruption (CMI) differ from one another. For instance, SCE estimates a value of $2.91 for avoided CMI which is slightly higher relative to PG&E's estimated $2.68 per avoided CMI. This difference is in part attributed to the different proportions of various customer classes like commercial, industrial, residential, and agricultural classes that make up the IOUs' service territories.

Furthermore, the utilities have different methodologies for estimating the number of avoided outage minutes that are obtained through smart grid technologies. As was shown on Table 1 on page 7, SCE estimated 219 million avoided CMI for 2018, which is roughly three times higher than PG&E's estimated 72.2 million avoided CMI, even though both utilities serve a similar number of customers in similarly-sized service territories. Additionally, SCE's avoided CMI figure is about 64 times higher than SDG&E's 3.4 million CMI, but SDG&E is comparatively a much smaller utility relative to SCE.[113] As a consequence of SCE's higher estimate for avoided CMI relative to the other IOUs, SCE's calculated reliability benefits are significantly higher than those recorded by SDG&E and PG&E. The costs and

[112] FLISR is a software system integrated into the utilities' outage management system that limits the impact of outages by quickly opening and closing automated switches and reconfiguring the flow of electricity through a circuit. By reconfiguring the flow of electricity, FLISR can minimize the number of customers impacted by an outage and to isolate the outage to reduce restoration times. With FLISR, outages that may have been one- to two-hours in duration can be reduced to less than five minutes.

[113] According to SCE and PG&E, this is the result of different estimation methodologies for avoided outages. SCE calculates their theoretical CMI for each circuit using modeling through a program called CYME and compares this to the actual CMI for each circuit. SCE takes the difference between the two to obtain the avoided CMI which can later be used to calculate the reliability benefit by multiplying by $2.91 per CMI. SCE assumes the benefits of their distribution automation is available on all circuits that have distribution automation technologies installed. On the other hand, PG&E obtains their estimated avoided CMI from their FLISR program based on comparing to outage data from 2013 as a baseline. PG&E's calculated difference represents their avoided CMI from their smart grid technologies installed since 2013 and similar to SCE, this figure would be multiplied by their cost per CMI ($2.68) to obtain PG&E's estimated reliability benefit.

benefits shown in Table 1 on page 7 were accrued from July 1, 2017, to June 30, 2018, which is the reporting period of the 2018 IOU annual update reports.

According to the IOUs, smart meter deployments continued to provide value during the reporting period. The Utilities also reported benefits to customers, markets, and the utility from automation projects. Environmental benefits related to the integration of renewable energy generation resources, both centralized and distributed, as well as those related to electric vehicles were noted. Other identified benefits relate to operational, reliability, and demand response/energy conservation. Smart Grid investments continue to contribute to a safe, reliable, resilient, and sustainable grid.

1.Customer Empowerment

The IOUs consider the customer to be an integral part and prominent driver of the Smart Grid program. They aim to provide customers with information such as energy usage, rates, energy conservation, and peak-load reductions. Using this information, customers will be empowered to better understand and manage their energy use and costs, including their use of time-variant rates. Applications and tools are designed to meet customers' evolving communication preferences and expectations. Projects that deliver information, services, and control pursued by customers themselves and that enable demand response, dynamic pricing, and HANs are included in this category.

2.Transmission and Distribution Automation/Utility Operations

Transmission Automation and Reliability (TAR) and Distribution Automation and Reliability (DAR) projects improve the Utilities' information and control capabilities on both the transmission and distribution levels of the electric grid. TAR projects provide the wide-area monitoring, protection, and control tools necessary to monitor bulk power system conditions, to safely and reliably incorporate utility-scale intermittent power generation; and to prevent emerging threats to transmission system stability. DAR projects similarly provide the ability to safely and reliably incorporate high penetrations of distributed energy resources on the distribution level, including the increasing load of electric vehicles. DAR projects also detect and isolate faults, provide "self-healing"[114] benefits, and provide optimization of voltage and reactive power to enhance power quality and to decrease energy consumption. TAR and DAR help deliver a Smart Grid that has the infrastructure necessary to support the integration of demand response, energy efficiency, distributed generation, and energy storage.

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[114] Self-healing benefits refer system reliability benefits derived from a network of sensors, automated controls, and advanced software that utilize real-time distribution data to detect and isolate faults and to reconfigure the distribution network to minimize the customers impacted.

3.Cyber and Physical Grid Security

Physical and cybersecurity investments are becoming more important as the communications and control systems needed to enable Smart Grid capabilities increase in size and reach. These systems have the potential to increase the reliability risks of the electric grid if the systems are not properly secured. The security programs of the IOUs enhance security throughout the network to resist attack, and to manage compliance and risk. Security is paramount to the full development, implementation, operation, and management of the Smart Grid.

4.Integrated and Cross-Cutting Systems

Integrated and cross-cutting systems refer to activities that support multiple areas of utility operations and may involve such systems as grid communications, data management and analytics, and advanced technology testing. An integrated approach helps to ensure that the overall network is efficient and delivers benefits across IOU operations and to customers. Integrated communications systems will provide solutions to enable sensors, metering, maintenance, and grid asset control networks. Over the long term, these systems will enable information exchange among IOUs, service partners, and customers by way of secure networks. Advanced technology testing and standards certification are fundamental for the Utilities to accommodate new devices from vendors. Workforce development and advanced technology training will also be required to enable the successful deployment of new technologies and to ensure that the IOUs are prepared to make use of emerging technologies and tools, which will maximize the value of these technology investments.

5.Asset Management, Safety, and Operational Efficiency

This category enhances monitoring, operating, and optimization capabilities to achieve more efficient grid operations and to improve asset management. These projects enable the Utilities to manage the maintenance and replacement of the grid’s infrastructure on a health-basis rather than on a time-in-service-basis, which should minimize critical equipment failure. This functionality also helps the IOUs manage costs associated with maintaining and replacing equipment.

4.1.1 Advanced Metering Infrastructure Deployment

Table 4 Advanced Metering Infrastructure (aka Smart Meters) Rollout[115] as of Oct. 2018[116]

IOU	Total Number of Electric Smart Meters (Millions)	Cumulative Electric Smart Meter Opt-outs[117] (No. of customers)	Percentage of Opt-outs	Annual Customer Complaints (escalated)[118]
PG&E	5.40	47,967	0.88%	12
SDG&E	1.45	4,217	0.29%	0
SCE	5.12	22,972	0.45%	442
Total	11.97	75,156	0.63%	454

Source: IOU 2018 Smart Grid Reports and Data Requests

In 2007, with Commission approval, the IOUs began full deployment of Advanced Meter Infrastructure, which was largely completed in 2013. Electric Smart Meter opt-outs refer to customers who have either declined to adopt smart meters or returned to using analog meters. The percentage of opt-outs relative to the total number of customer accounts with Smart Meters has remained less than one percent for all the IOUs. Annual escalated customer complaints have decreased over the past year by 50, or by 9.92 percent.

4.1.2 Utility De-energization

The State's Investor Owned Utilities, PG&E, SCE, and SDG&E have general authority to shut off electric power to protect public safety under California law, specifically California Public Utilities Code Sections 451 and 399.2(a). This process is called de-energization or Public Safety Power Shutdown (PSPS). This authority includes shutting off power if the utility reasonably believes that there is an "imminent and significant risk" that strong winds may topple power lines or cause major vegetation-related damage to power lines, leading to increased risk of fire.

[115] These statistics only include data as reported by the State's electric Utilities in the Smart Grid Annual Reports. The State's gas Utilities have also deployed millions of Smart Meters.
[116] The reporting period was from November 1, 2017 to October 31, 2018.
[117] Opt-out totals listed here are since the beginning of the Smart Meter programs.
[118] Escalated complaints are customer complaints regarding smart meters that have gone through the complaint process and reached resolution during the reporting period.

The State's utilities will de-energize electric facilities only during periods of extreme fire hazard and only after weighing several criteria including fuel conditions, weather forecasts, and on the ground real-time observations. As potentially hazardous conditions develop, the utilities will inform the CPUC, California Governor's Office of Emergency Service (CalOES), and the California Department of Forestry and Fire Protection (CAL FIRE) as well as local public safety authorities of the potential for a PSPS event. Following these notices, the utilities will conduct outreach to impacted customers informing them of the potential for a power shutdown via multiple channels. If the hazardous conditions continue to develop the utilities will proceed with de-energizing electric facilities within the impacted area. Following the weather event utility crews will inspect all de-energized lines and restore power to impacted communities.

On July 12, 2018, the CPUC adopted rules to strengthen customer notification requirements before de-energization events and ordered utilities to engage local communities in developing de-energization programs. Additionally, the CPUC is working with the CalOES, CAL FIRE, and first-responders throughout the state to address potential impacts of utility de-energization practices on emergency response activities, including evacuations. The CPUC will continuously assess implementation of de-energization programs by utilities, including performing a thorough review of de-energization events as they occur.

4.2 Highlights of San Diego Gas & Electric's (SDG&E) Smart Grid Deployment

This section provides information on SDG&E's estimated expenditures and benefits realized during the reporting period, and it highlights some of SDG&E's projects.

Costs

Table 5 SDG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2017 through June 30, 2018

Task	Value
Customer Empowerment and Engagement	$1,292,000
Distribution Automation and Reliability	$54,031,000
Transmission Automation and Reliability	$4,859,000
Asset Management, Safety and Operational Efficiency	$25,546,000
Security	$8,212,000
Integrated and Cross-Cutting Systems	$1,978,000
Total Estimated Costs	$95,918,000

Benefits

Table 6 SDG&E's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2017 through June 30, 2018

Benefit	Value
Reliability Benefits	$34,057,000
Physical and Cybersecurity Benefits	$11,714,000
Customer Demand Response Benefits	$610,000
Avoided Costs (Operational, Capital, Environmental)	$62,686,000
Total Estimated Benefits	$109,067,000
Avoided Outage Minutes	3.4 Million

Highlights of SDG&E's Smart Grid deployment update include:

- SDG&E saw significant growth in NEM distributed generation (DG) with residential and commercial customers connecting nearly 21,000 new systems (primarily solar), bringing the total number of interconnected DG systems interconnected to nearly 134,754;

- Customer energy storage deployments grew rapidly in the commercial/industrial sector and additional growth is anticipated among residential customers as more products enter the market and time-of-use rates go into effect;
- There are more than 110 MWs of energy storage connected to SDG&E's local power grid (34 MW of which are customer-sited) including the world's largest lithium-ion battery facility— AES Energy Storage's 30 MW lithium-ion energy storage facility in Escondido, Ca; and
- Plug-in electric vehicle penetration grew to nearly 30,000 vehicles, which is 4,100 more than the previous year.

4.2.1 SDG&E Example Projects

- **Demand Response Management System (DRMS)** – The DRMS project enables integrated management of SDG&E's entire demand response portfolio. This includes program and device management, forecasting, settlement, and analytics/reporting. In Phase 1 of the project, SDG&E implemented functionality to send text messages, facilitate two-way demand response load control, and send price signals to meter-connected HAN devices, and monitor device connectivity. The second phase, which delivers DR post event settlement capabilities for the capacity bid program and business reporting, began in Q3 of 2017 and was completed in July 2018. Additionally, SDG&E's project team enabled wholesale market integration for both programs in its portfolio and for third-party demand response providers.[119] .
- **Borrego Springs Microgrid** – This project seeks to establish a microgrid demonstration at an existing substation to evaluate the effectiveness of integrating multiple DER technologies, feeder automation system technologies, and outage management system (OMS) to improve reliability during outages. The most recent phase of this project enhanced the existing microgrid during the reporting period by expanding the microgrid to the entire distribution substation. The Borrego Springs Microgrid can island all three circuits out of Borrego Springs, which has a peak load of 14 MW and serves about 2,500 residential and 300 commercial and industrial customers. Additionally, the DERMS controller was successfully deployed for the Borrego Microgrid during the reporting period.

[119] Enabling wholesale market integration for third-party demand response providers is also known as direct participation demand response, which is described in Rule 32. Please see the following link for more information: https://www.sdge.com/sites/default/files/elec_elec-rules_erule32.pdf.

- **Advanced Distribution Management System (ADMS)** – The purpose of this project is to implement new functions within the new Outage Management System/Distribution Management System (OMS/DMS) that were to enhance distribution grid management. In Phase 1 of the project, SDG&E implemented OMS enhancements such as service alerts, an outage website, and mobile improvements. Additionally, SDG&E developed enhanced DMS features for power flow analysis, Fault Location Analysis, Feeder Load Management, Suggesting Switching, Fault Location Isolation Service Restoration, and Volt/Volt Amperes Reactive (VAR)[120]. In Phase 2, SDG&E focused on modeling and integrating DERs into the DMS to improve power flow forecasts, to enhance functionality, and to provide visibility to the distribution operator of the impacts these DERs present to the distribution grid. Phase 3 implemented functionalities that provide optimal power flow results, the ability to view feeder load management results for any device on the system and rolled out FLISR in automatic mode to the entire eligible SDG&E service territory. In 2018, SDG&E implemented database and software upgrades for the network management system, which included FLISR improvements, automated outbound customer call interface for outages, a voltage read function for Smart Meters, and the inclusion of customer history data.
- **SCADA Expansion**– For this project, SDG&E plans to install 300 SCADA line switches to have an average of 1.5 switches on every distribution circuit. Additionally, SDG&E will install SCADA at 13 existing substations. In 2018, SDG&E installed SCADA at the Carlton Hills substation and has implemented SCADA capabilities at the Capistrano, Poway and Pendleton substations. SDG&E also identified prospective substation sites for SCADA expansion at Descanso, Rancho Santa Fe, and Warners substations, which are slated to be completed in 2019.

[120] Volt Amperes Reactive (better known as VAR) is a unit of reactive power.

4.3 Highlights of Southern California Edison (SCE) Smart Grid Deployment

This section provides information on SCE's estimated expenditures and benefits realized during the reporting period, and it highlights some of SCE's projects.

Costs

Table 7 SCE's Estimated Smart Grid Costs for Fiscal Year July 1, 2017 through June 30, 2018

Task	Value
Customer Empowerment and Engagement	$13,117,000
Distribution Automation and Reliability	$52,191,198
Transmission Automation and Reliability	$0[121]
Asset Management, Safety and Operational Efficiency	$1,452,574
Security	$0[122]
Integrated and Cross-Cutting Systems	$11,215,244
Total Estimated Costs	$77,976,016

[121] There were no active projects in this category during the reporting period.

[122] The Common Cybersecurity Services (CCS) platform project was completed and deployed during the 2016 update reporting period.

Benefits

Table 8 SCE's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2017 through June 30, 2018

Benefits	Value
Reliability Benefits[123]	$638,000,000
Physical and Cybersecurity Benefits	N/A[124]
Customer Demand Response Benefits[125]	$10,800,000
Avoided Costs (Operational, Capital, Environmental)	$60,300,000
Total Estimated Benefits	$709,100,000
Avoided Outage Minutes	219 Million

Highlights of SCE's Smart Grid deployment update include:

- SCE received approval of a $356 million budget to build out its transportation electrification infrastructure and has deployed a cumulative total of 941 charge ports at 60 customer sites (462 ports are in disadvantaged communities);
- SCE received approval of two new TOU rate periods to shift its current peak period for 3.3 million residential customers to incentivize them to shift their load to lower cost periods;
- SCE integrated most of SCE's DR programs into the CAISO market and completed end-to-end integration connectivity from the CAISO Automated Dispatch System down to a customer load control device;
- SCE installed 357 remote control switches and 6 remote reclosers as part of its efforts to automate distribution circuits, enhance overall system performance and reliability;

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123 In past reports, this benefit was calculated based on Lawrence Berkeley National Laboratory's Value-of-Service (VOS) reliability model. In support of SCE's 2018 GRC filing, SCE has changed how reliability improvements are calculated that are achieved through distribution automation and how those improvements are valued through updating its VOS estimates. The other utilities have not similarly updated their VOS estimates. The modified approach indicates a significant increase in calculated reliability benefits relative to past reports. (Smart Grid Annual Deployment Plan Update, p.8). As a disclaimer, this data point is shown as it was reported by SCE to the CPUC. This method has not been vetted by the Commission and the CPUC cannot attest to its accuracy.

124 SCE's pilot projects did not specifically track physical and cybersecurity costs and benefits.

125 According to SCE, "Demand Response benefits are specifically attributed to demand response enabled by Auto-DR technology and controllable programmable communicating thermostats for SCE's PTR-ET-DLC program."

- SCE implemented distribution Volt/VAR control, in order to coordinate and optimize voltage and VARs across all circuits fed by a substation, has been completed at 182 substations across SCE's service territory.

4.3.1 SCE Example Projects

- **3rd Party Smart Thermostat Program** – SCE is working with some of the leading Internet-connected smart thermostat vendors and system providers to enroll customers in a demand response program that utilizes smart meter interval data. After the two-year study in 2013 and 2014, and after SCE started the Save Power Day program in June 2015, SCE had approximately 47,947 participants enrolled at the end of the 2018 reporting period and estimates reaching up to 130,000 enrollments by 2020.

- **Residential TOU Default Pilot**– SCE launched a TOU default pilot in December of 2017. 400,000 residential customers were randomly selected and assigned to one of two new TOU default rates to test their behavior and retention. SCE launched communications in December 2017 that informed customers of the upcoming change, the potential bill impacts and provided them with the options of (1) opting out for TOU altogether, (2) switching to another TOU option, and (3) do nothing and were defaulted in March 2018. The findings will inform SCE as it prepares for a full of residential TOU beginning in 2020. Findings thus far from the pilot and survey data have shown that:

    - Less than 1% of the defaulted customers have requested to go back to the tiered rate structure.
    - Customer awareness of TOU rate plans increased from 47% to 72%.
    - Customer awareness of rate plan options increased from 35% to 41%.
    - Customer awareness of being transitioned to a TOU rate increased from 40% to 49%.
- **Circuit Automation** – SCE began this program in order to automatically or remotely restore power to customers after outages caused by faults and to minimize the impact on customers of outages that occur in the ordinary course of business. During the 2018 reporting period, SCE installed 357 remote control switches, 6 remote sectionalizing reclosers, and spent $13.7 million.

- **Charge Ready Program** – The Charge Ready Program is an initiative to deploy electric vehicle charging stations at locations where EVs will be parked for four or more hours, such as multi-family dwellings, workplaces, fleet parking, and destination centers. SCE also conducts market education to develop awareness of EVs and their benefits to the grid. As of November 2018, SCE had 79 sites and 1,280 charge ports committed for overall deployment, and about one-third of these charge ports are located in disadvantaged communities.

4.4 Highlights of Pacific Gas & Electric (PG&E) Smart Grid Deployment

This section provides information on PG&E's estimated expenditures and benefits realized during the reporting period, and it highlights some of PG&E's projects.

Costs

Table 9 PG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2017 through June 30, 2018

Task	Value
Customer Empowerment and Engagement	$41,429,000
Distribution Automation and Reliability[126]	$53,450,000
Transmission Automation and Reliability	$64,300,000
Asset Management, Safety and Operational Efficiency	$9,300,000
Security	$5,560,000
Integrated and Cross-Cutting Systems	$21,635,000
Total Estimated Costs	$195,674,000

Benefits

Table 10 PG&E's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2017 through June 30, 2018

Benefits	Value
Customer Reliability Benefit[127]	$193,500,000
Customer Demand Response Savings	$255,100
Avoided Costs (Operational, Capital, Environmental[128])	$3,200,000
Total Estimated Benefits	$197,000,000
Avoided Outage Minutes[129]	72.2 million

[126] This figure includes $238.8 Million for the Distribution Substation SCADA program incurred since program inception. $44.8 Million were incurred during the reporting period.

[127] PG&E's customer reliability benefits are derived from calculating the monetary benefits from avoided customer outage minutes that were achieved through its FLISR program.

[128] For details on PG&E's Environmental developments, please see PG&E's Corporate Sustainability Report at: http://www.pgecorp.com/corp/responsibility-sustainability/corporate-responsibility-sustainability.page.

Highlights of PG&E's Smart Grid deployment update include:

- PG&E's Electric Program Investment Charge (EPIC) 3 portfolio includes technologies that will be able to promote grid adaptation to a changing climate and increased wildfire threats;
- Smart Meter outage information improvement reduced an estimated 8,000 "truck rolls"[130] and saved PG&E over $600,000 over the reporting period;
- Enhancing technology capabilities to improve wide-area monitoring, protection, and control enabled by supervisory control and data acquisition (SCADA) equipment in the transmission and distribution systems;
- Increasing customer awareness and engagement in managing their energy use, such as through providing nearly 55,000 EV customers with a time-of-use rate schedule to encourage off-peak charging;
- Improving PG&E's capabilities to effectively anticipate, prevent, and respond to a new and emerging class of cyber and physical threats to the grid.

4.4.1 PG&E Example Projects:

- **Distribution Supervisory Control and Data Acquisition (SCADA) Program** – This program is focused on increasing SCADA penetration in the distribution system and improving reliability for PG&E's customers. PG&E's goal is to achieve 100 percent visibility and control over all critical distribution substation breakers by 2019 through adding or replacing SCADA for approximately 560 substations and 1,930 breakers. By the end of the 2018 reporting period, the project had upgraded SCADA in 432 substations and 1,670 breakers.
- **Modular Protection Automation and Control (MPAC) Installation Program** – This program aims to deploy pre-engineered, fabricated, and standardized control buildings in transmission substations. These MPAC upgrades are performed in conjunction with other PG&E transmission substation upgrade projects such as business conversions, control center consolidation efforts, and aging asset replacement. As of 2018, PG&E has installed and completed 112 MPAC buildings.

[129] The avoided outage minutes are calculated based on customer interruption minutes that were saved as a result of FLISR technologies.
[130] Truck roll refers to a utility dispatch of technicians to investigate electrical equipment during an outage.

- **Time Varying Pricing –** This program, which includes TOU, peak-day pricing and SmartRate, is intended to charge customers different rates based on varying system conditions to more closely align retail and wholesale electricity generation costs and incentivize customers to shift their energy use to lower cost periods of the day. PG&E administers time varying pricing rates to all PG&E bundled residential and non-residential customer classes. Peak-day pricing provides between 25-40 MW of load reduction during the hottest days, which is equal to the generation of about two peaker plants. As of July 2018, 113,000 residential customers have enrolled in the SmartRate program, which provides an additional 20-25 MW of load reduction on event days. Furthermore, over 439,000 small to medium business service agreements have transitioned to TOU rates of the past 6 years and 160,000 actively participate in the peak day pricing program.
- **Electric Vehicle Infrastructure** – This program is a three-year pilot designed to enable the deployment of make-ready infrastructure[131] to support up to 7,500 EV level-2 charging ports located primarily in workplaces and multi-family housing. PG&E launched the program in January 2018 and received 256 applications for the program by the end of June 2018. At the close of Q2 2018, 56 sites for charging ports had been approved and moved into final design and preconstruction phases (including 3 which have completed construction and are fully operational). PG&E installed 80 ports by the end of the reporting period and is conducting solicitations for EV chargers.

[131] Make-ready refers to the utility making the infrastructure ready for third parties to build out the charging stations themselves. This entails the trenching, installation of conduit and electrical wire, pulling of wires, installing concrete installation bases (if needed), potential upgrades of existing electrical infrastructure including panel additions and transformer replacement, landscape removal, paving, and guard post installation.

5 Conclusion

The Smart Grid policies pursued by the State of California and implemented by the State's Utilities continue to generate benefits for California ratepayers. Based on the Utilities' estimates in their 2018 smart grid reports, the programs and projects the Utilities have implemented have realized over $1 billion in benefits in Fiscal Year 2017-2018. However, California still has more to do to realize the vision of a smart and modern grid that is prepared to meet California's ambitious energy and climate goals, as well as the challenges posed by the increasing cyber security threats and risk of wildfires and other extreme weather events. This will require the coordination of the CPUC and the electric IOUs to invest further in grid automation, grid hardening, and cybersecurity, smart inverters as well as increase the penetration of distributed energy resources such as electric vehicles, demand response, and energy storage. By fulfilling the vision of the DER Action Plan, the CPUC will help move California towards a sustainable, affordable, efficient, and effective grid of the future. With its rich tradition of entrepreneurship, technological innovation, and forward-looking regulation, California will continue to lead the nation in Smart Grid development and deployment.