California's Grid Modernization Report 2020

California Public Utilities Commission

CALIFORNIA'S GRID MODERNIZATION REPORT TO THE GOVERNOR AND LEGISLATURE

February 2021

About This Report

Each February, the California Public Utilities Commission reports to the Legislature and Governor on progress made in the past year towards achieving the State's smart grid goals per Public Utilities Code Section 913.2.

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CONTENTS

TABLES IN THE REPORT

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CPUC PRESIDENT'S LETTER

Grid modernization policies and utility projects deployed in 2020 continue to advance California's bold energy and climate goals. In the past year, the California Public Utilities Commission (CPUC) continued to make great strides toward a modern, safe, clean, and reliable electric grid through numerous grid modernization policy developments.

This year, the CPUC, in ongoing efforts to build resilient communities, adopted rates, tariffs, and rules to facilitate commercialization of microgrids across California, and approved strategies for procurement of backup power in advance of the wildfire season. We approved measures to accelerate electric vehicle and infrastructure deployment in California, including strategies to help electric vehicles charge in ways that are beneficial for the electrical grid, and new rate structures to encourage more commercial electric vehicle customers. The CPUC approved 1,207 megawatts of new investor-owned utility storage procurement in 2020, the most ever in a single year. We also took further action to focus electricity research, development, and deployment projects to better connect ratepayer-funded projects with current and emerging policy issues in equity, wildfire mitigation, transportation electrification, and utility public safety power shutoffs.

With the rising frequency and potency of catastrophic wildfires in California, the electric utilities are increasing the use of grid modernizing technologies to enhance safety, reliability, and resiliency of California communities. The utilities' wildfire safety related investments include grid hardening measures like installing covered conductors, steel poles, and selective undergrounding of power lines; operating supervisory control and data acquisition technology to remotely disable reclosing devices to reduce the risk of contact-related ignitions; and using distribution sectionalizing devices, transmission line switching, and microgrids with backup generation to reduce the impact of utility public safety power shutoffs.

These efforts will help us chart a path toward building a stronger, more resilient grid that can meet the state's ambitious clean energy future.

Marybel Batjer
President, California Public Utilities Commission
January 2021

1. EXECUTIVE SUMMARY

California's Grid Modernization Report provides an annual overview of progress the California Public Utilities Commission (CPUC) made on smart grid policy goals and recommendations, which began in 2006 with the authorization of advanced metering infrastructure deployment. In combination, policy and planned deployments aim to deliver clean energy and energy usage data to Californians through a modern, safe, cost-effective, efficient, and reliable electric power grid. The report highlights: 1) deployments of grid modernizing technologies made possible through years of policy work affecting the electric power grid in each of the state's three largest electric investor-owned utilities' (IOUs or the utilities)[1] service territory, and 2) estimates of related costs and benefits to ratepayers.[2]

Initially, Senate Bill 17 (Padilla, 2009), codified in Public Utilities Code Sections 8360-8369, required in Section 8367 that, "By January 1, 2011, and by January 1 of each year thereafter, 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." Subsequently, Senate Bill 1222 (Hertzberg, 2016), consolidated CPUC reporting requirements and added Public Utilities Code Section 913.2, which requires, "By February 1 of each year, 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

1 The three largest electric investor-owned utilities in California are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

2 "By February 1 of each year, 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." (Public Utilities Code Section 913.2).

costs and benefits to ratepayers." In compliance, key sections of *California's Grid Modernization Report* include:

- An introduction to the report (Section 2);
- CPUC grid modernization regulatory policy work in 2020 (Section 3.1);
- CPUC grid modernization regulatory policy work expected in 2021 (Section 3.2); and
- IOU grid modernization deployment projects, and overall ratepayer costs and benefits. (Section 4).

In the 11 years since SB 17 was adopted, the deployment of distributed energy technologies has, in some cases, far exceeded the expectations of "smart grid" proponents and, in other cases, continued to face challenges. In either case, the thinking behind the terminology used by proponents of developing advanced communications to better manage the electric grid and effectively integrate distributed energy resources (DERs) has moved beyond the simple catch phrases of a smart grid. This annual report has evolved as well. While the report is still produced in compliance with Public Utilities Code Section 913.2 to report on policy and program advancements related to Sections 8360 through 8369, the report offers a broad update on efforts related to distributed energy resources, smart grid, and grid modernization, which is now reflected in the updated title *California's Grid Modernization Report*. The report continues to be produced for the Governor and Legislature in compliance with Public Utilities Code Sections 913.2, which requires the CPUC to report on policies and programs broadly related to Sections 8360 through 8369. Given that the bulk of this report submitted in compliance with Section 913.2 centers on distributed energy resources and the grid, the report requirements could be refined and merged with the requirements of related Section 913.6, which focus on "the impacts of distributed energy generation on the state's distribution and transmission grid."

California Grid Modernization Report – Key 2020 Developments

In 2020, the CPUC continued to make progress towards a modern, safe, clean, cost-effective, efficient, and reliable electric grid through the following CPUC policy developments:

- **Distribution Resources Plan (DRP)[3]** – Public Utilities Code Section 769 requires the CPUC to create a framework for reducing barriers to distributed energy resources deployment and targeting distributed energy resources deployments that avoid or defer utility capital investments. In response to this regulatory code, the CPUC adopted the Distribution Investment and Deferral Framework (DIDF) in Distributed Resources Planning (DRP) proceeding (R.14-08-013). DIDF is an ongoing annual process to identify, review, and select opportunities for competitively sourced distributed energy resources to defer or avoid utility traditional distribution capital investments. In 2020, the CPUC implemented a reform process and adopted over 50 reform elements in the DIDF to improve outcomes in procurement of DERs[4] when they are lower cost alternatives to traditional utility infrastructure. In another DRP framework called integration capacity analysis (ICA), each utility analyzes its distribution grid for its capacity to integrate DERs into different sites. Each utility publishes an ICA map designed to help DER developers site projects in locations less likely to trigger costly distribution upgrades in the interconnection process. Pacific Gas and Electric Company (PG&E) made significant updates to its integration capacity analysis implementation as all three IOUs continue to make refinements to their ICAs.

3 Explore more at the CPUC Distribution Resources Plan page and proceeding docket cards of Rulemaking (R.) 14-08-013, Liberty Application (A.) 15-07-007, PG&E A.15-07-006, and SCE A.15-07-002.

4 Distributed energy resources are energy resources on the electricity distribution grid, which may include distributed renewable generation resources (e.g. rooftop solar PV), energy efficiency, energy storage (e.g. large batteries), 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 (IFOM).

The CPUC initiated a process to increase the accuracy of ICA maps, so they may help streamline the interconnection process.

- **DER Action Plan**[5] – The Distributed Energy Resources (DER) Action Plan serves as a roadmap across more than ten DER-related proceedings for decisionmakers, staff, and stakeholders working in support of California's DER future. The plan facilitates active, coordinated, and forward-thinking development of related DER policy and is intended to guide development and implementation of policy related to DERs, not to determine outcomes of individual proceedings. The plan supports CPUC's Strategic Directives[6] related to rates and affordability, climate change, environmental sustainability, economic prosperity, and coordination with other governmental entities. While most of the DER Action Plan action elements are completed, the CPUC is working towards an updated, new DER Action Plan in 2021 to prepare for an even higher volume of DERs and other developments in grid modernization, market integration, advanced rate design, and DER program integration.

- **Integrated Distributed Energy Resources (IDER)**[7] – The CPUC released a Staff Proposal for DER Tariffs and Requests for Offers (RFOs) Streamlining. The purpose of the proposal is to: 1) present DER deferral tariffs for sourcing alternatives to RFOs with the aim of increasing the number of DER deferral projects based on grid needs identified in the DRP DIDF process; and 2) address the issues with the current DIDF annual RFO procurement process that increase risk for both DER providers and ratepayers. The proposal has three elements: 1) a new DER Tariff focused on aggregation of behind-the-meter (BTM) DERs; 2) a new Standard

5 Find more here: CPUC Distributed Energy Resource (DER) Action Plan.

6 The CPUC's Strategic Directives were updated in February 20, 2019.

7 Discover more on the CPUC Integrated Distributed Energy Resources page and proceeding docket card R.14-10-003.

Offer Contract (SOC) to expedite procurement of in front of the meter (IFOM) DERs; and 3) streamlining the existing DIDF RFO process to reduce timelines and regulatory burden to improve procurement outcomes. The CPUC approved the Staff Proposal with modifications in a Decision (D.21-02-006) in February 2021.

- **Microgrids**[8] – The CPUC focused on the commercialization of microgrids and development of resiliency strategies to implement Senate Bill (SB) 1339 (Stern, 2018). In June 2020, the CPUC approved a Track 1 Decision, which implements resiliency measures in advance of the 2020 fire season, including streamlining the DER interconnection process and removing barriers to using battery energy storage for backup power. In September 2020, staff developed a concept paper classifying microgrid types and describing the barriers to microgrid commercialization. Then, in January 2021, the CPUC approved a Track 2 Decision (D.21-01-018) focused on fulfilling the intent of the Legislature, including a microgrid incentive program and microgrid tariff, among other orders. The Decision also included a framework for transitioning away from using temporary diesel generation to power substations during public safety power shutoff events. Staff has also launched a working group to further explore microgrid and resiliency policy; meetings will occur throughout 2021.

- **Rule 21 Interconnection**[9] – Rule 21 governs interconnection for most DERs. The open rulemaking proceeding requires a series of public working groups to develop proposals to address interconnection issues and recommend proposals on these issues. The Rule 21 Working Group Four submitted its final report in August 2020 for CPUC action to streamline the interconnection process in the following areas: anti-islanding requirements, interconnection processes to

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[8] Learn more at the CPUC Resiliency and Microgrids page and proceeding docket card R.19-09-009.

[9] Visit the CPUC Interconnection (Rule 21) page and proceeding docket card R.17-07-007 for more.

facilitate implementation of California Zero Net Energy building codes, and implementation of Distributed Energy Resource Management Systems (DERMS). In September 2020, the CPUC approved D.20-09-035, which adopted recommendations from Rule 21 Working Groups Two and Three and the Vehicle-to-Grid Alternating Current (V2G AC) Interconnection subgroup. This Decision represents significant progress toward maximizing the renewable energy generation that can be safely integrated with existing grid infrastructure, establishing a path forward for vehicle to grid interconnection while streamlining and automating the interconnection process.

- **Smart Inverters**[10] – In June 2020, smart inverter Phase 2 communications requirements (Phase 2) and the majority of the Phase 3 advanced functions (Phase 3), which will allow the grid to support additional distributed generation while contributing to grid stability, became mandatory for new inverter based interconnections under Rule 21. In August 2020, the Smart Inverter Working Group (SIWG) reconvened to develop recommendations for cybersecurity requirements that will facilitate the secure operation of communications (Phase 2 requirements) and consider updates to Rule 21 to reflect recent revisions in nationally recognized smart inverter standards. In September 2020, the CPUC approved D.20-09-035, which updates Rule 21 to integrate newly available smart inverter capabilities into the IOU DER interconnection processes and allows the use of non-default smart inverter settings, where possible, to avoid the need for grid upgrades.

- **Energy Storage**[11] – The CPUC approved 1,207 MW of new IOU storage procurement in 2020, the most it has ever approved in a single year. The

[10] Browse the CPUC Smart Inverter Working Group page for more.

[11] See CPUC Energy Storage page.

majority of the procurement was driven by system capacity needs identified in the Integrated Resource Planning (IRP) proceeding. A small fraction of procurement of energy storage included deferral of distribution grid investments. Furthermore, the CPUC selected a contractor for an evaluation of the California Energy Storage Procurement Framework. The CPUC also developed two scopes of work for research projects, one on long duration storage and another on the potential of behind the meter (BTM) storage (customer-side) to reduce grid integration costs associated with implementation of Title 24 Zero Net Energy (ZNE) building requirements. Finally, the CPUC approved the implementation plan for PG&E's "WatterSaver" Program to enable shifting of electric water heating load with smart water heaters.

- **Transportation Electrification**[12] – The CPUC continued efforts to accelerate transportation electrification, implement requirements of SB 350 (De León, 2015), and support the numerous Executive Orders establishing electric vehicles (EV) adoption goals and EV charging deployment goals from both Governor Newsom and former Governor Brown. The CPUC approved the largest single-utility investment in transportation electrification to date. This program authorized Southern California Edison Company (SCE) to spend $436 million to fund approximately 37,800 new EV chargers. The CPUC also issued several other decisions in 2020, including a new time-of-use (TOU) rate for San Diego Gas and Electric Company's (SDG&E's) commercial EV customers, a decision authorizing low carbon fuel standard (LCFS) credit revenue spending on equity and resiliency projects, and a decision implementing SB 676 outlining future actions on vehicle-grid integration (VGI). Since 2016, the CPUC has approved more

[12] See the CPUC Zero-Emission Vehicles page and proceeding docket cards of the DRIVE Rulemaking R.18-12-006, SCE Charge Ready Phase 2 A.18-06-015, SDG&E High-Powered EV Charging Rate A.19-07-006, SDG&E Power Your Drive Extension A.19-10-012, and Low Carbon Fuel Standard Program R.11-03-012.

than $1.6 billion of ratepayer spending for transportation electrification. The CPUC is in the midst of a process to develop a long-term framework for IOU transportation electrification investments and grid planning called the Transportation Electrification Framework.

- **Demand Response (DR)**[13] – IOUs conducted Demand Response Auction Mechanism (DRAM) auctions for 2020 and 2021 and procured 216 MW and 206 MW (August capacity), respectively, from third-party DR providers; this follows the 2019 extension of the demand response auction mechanism (DRAM) pilot (2020-2023). As part of the CPUC authorized annual refinement process, the CPUC refined the upcoming DRAM auctions in 2022 & 2023. An independent DRAM pilot evaluation report is anticipated in the fourth quarter of 2021. Three third-party DR providers were qualified via CPUC's Load Impact Protocol review process to provide DR for resource adequacy to non-IOU load-serving entities (LSEs) such as community choice aggregators in 2021. Extensive analysis of how DR resources performed during the 2020 heat waves was completed for the recently published joint-agency Root Cause Analysis Report. The analysis indicated that while some DR resources performed well and helped mitigate grid reliability issues, other DR resources underperformed or were not utilized by the California Independent System Operator (CAISO) market. The CPUC opened an emergency Summer Reliability Rulemaking in November 2020 to consider potential DR measures and other supply side solutions for implementation by Summer 2021 in order to help avoid a recurrence of reliability issues during future heat waves.

[13] Find more on the CPUC Demand Response page and the proceeding docket cards of the Demand Response Enhancement Rulemaking R.13-09-011 and the consolidated 2018-2022 Demand Response Program applications of SDG&E A.17-01-019, SCE A.17-01-018, and PG&E A.17-01-012.

- **Enhanced Reliability Reporting**[14] – Enhanced reliability reporting supports the State's grid modernization efforts by increasing transparency into the reporting metrics for reliability standards and requiring the IOUs to publicly describe the remediation efforts they plan to take to address the worst performing circuits. As a result, communities and individuals can also access the enhanced reliability reports online at any time. Outage duration per customer and frequency of outages per customer metrics were largely better than the national median of averages reported to the United States Energy Information Administration (U.S. EIA). For instance, the national median for average outage duration per customer is 99.8 minutes per customer, while PG&E, SCE, and SDG&E reported average 117.7, 90.8, and 68.6 minutes per customer respectively. However, duration per event metrics were worse than the national median of U.S. EIA reported averages. For example, the national median for average duration per event was 95.4 minutes per outage; PG&E, SCE, and SDG&E reported average outages of 116.5, 104.8, and 115.2 minutes respectively.

- **Customer Data Access**[15] – The click-through authorization process, released in 2018, allows customers to easily share their energy related data with third-party demand response providers of their choice. The CPUC is considering IOU applications to expand and improve the click-through process in an active proceeding A.18-11-015, et. al, with a decision expected in early 2021. Regional planners are now able to target energy programs in geographical areas to help combat climate change with the release of the Energy Atlas 2.0 geospatial tool in August 2019.

[14] Learn more about CPUC Reliability Standards and CPUC Reliability Reports.

[15] Access more via the proceeding docket card for IOU click-through process authorization proposals A.18-11-015.

- **EPIC Reauthorization**[16] – D.20-08-042 reauthorized the Electric Program Investment Charge (EPIC) for 10 more years, from 2021-2030. The California Energy Commission (CEC) will continue to annually administer the $147.26 million budget. Grid-focused EPIC projects fall broadly into four categories: (1) integration of renewables and distributed energy resources into the grid; (2) grid modernization and optimization; (3) customer focused products and services, including integration of Demand-Side Management for grid optimization; and (4) cross-cutting efforts to better prepare and respond to natural disasters and support next generation infrastructure.

[16] Charge up at the CPUC EPIC page and proceeding docket card R.19-10-005.

2. INTRODUCTION

2.1. WHAT IS THE SMART GRID?

Historically, the term smart grid meant different things depending on the goal of the party using the term, but it generally referred to the use of digital technologies to transmit measurements to grid operators and better integrate renewable and distributed energy resources onto the electric grid. SB 17 states objectives of a smart grid as promoting:

1) Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid;
2) 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;
3) Deployment and integration of cost-effective distributed resources and generation, including renewable resources;
4) Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources;
5) 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;
6) Integration of cost-effective smart appliances and consumer devices;
7) 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;
8) Provision of timely information and control options to consumers;

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

In the 11 years since SB 17 was adopted, the deployment of distributed energy technologies has, in some cases, far exceeded the expectations of "smart grid" proponents and, in other cases, continued to face challenges. In either case, the concepts and notions behind the terminology used by proponents of developing advanced communications to better manage the electric grid and effectively integrate distributed energy resources has moved beyond the simple catch phrases of a smart grid. This annual report has evolved as well. It is now titled *California's Grid Modernization Report* as it is now a complete report on grid modernization. The report continues to be produced for the Governor and Legislature in compliance with Public Utilities Code Section 913.2, which requires the CPUC to report on policies and programs broadly related to Sections 8360 through 8369. One option is to merge the requirements of Public Utilities Code 913.2 with Section 913.6. The latter focuses on "the impacts of distributed energy generation on the state's distribution and transmission grid." Given that the bulk of this report submitted in compliance with Section 913.2 centers on distributed energy resources and the grid, the report requirements could be refined and streamlined.

2.2 CALIFORNIA'S GRID MODERNIZATION PROGRESS

The CPUC worked with the Legislature and IOUs in California on numerous priorities throughout 2020 and in years past to modernize the electric grid as explained in this section. Recent grid modernization progress builds upon advanced meter[17] deployment authorized in 2006 and investments in 2009 in technologies, such as smart grid pilots in the city of Irvine, digital control and communications technology, power electronics, and advanced automation.

The accelerating adoption of customer-side DERs – primarily intermittent solar photovoltaic (PV) systems as well as storage and electric vehicles – presents new operational challenges and opportunities for the grid. Current grid modernization efforts focus on streamlining and simplifying interconnection processes, so DERs may interconnect to the grid in a "plug-and-play" manner.[18] To that end, Rule 21 Working Groups recommended and the CPUC adopted a process to streamline and automate electric vehicle integration into the grid in 2020.

Grid modernization investments may increase grid reliability and reduce safety risks associated with both customer's and IOU's higher adoption of DERs. Additionally, the Distribution Resources Plan proceeding R.14-08-013[19] requires each utility to provide details in its general rate case (GRC)[20] on any additional utility spending necessary to integrate cost-effective distributed energy resources into distribution system planning consistent with the goal of yielding net benefits to ratepayers.

Furthermore, the CPUC remains committed to maintaining and improving the safety, reliability, and affordability of electric power as well as reducing the environmental impact of electric power generation, transmission, distribution, and retailing. The rising

[17] Advanced meter refers to modern electrical meters that can transmit customer energy usage data directly to the utility and customer through its cellular network on a frequent schedule, so the utility does not need to send a person to obtain this data.

[18] Creating a "plug-and-play" distribution grid involves dramatically streamlining and simplifying the processes for interconnecting energy assets to the distribution grid, so DERs can precipitously, seamlessly integrate.

[19] Pursuant to Public Utilities Code Section 769, CPUC Rulemaking R.14-08-013 considers the IOUs' DRPs.

[20] General Rate Cases are ratesetting proceedings, where the CPUC approves the costs of constructing, operating, and maintaining each utility's infrastructure and the utility's rate of return, then allocates those costs among customer classes.

frequency and potency of catastrophic wildfires in California and the utilities' present-day use of public safety power shutoff (PSPS) events to reduce the incidence of utility equipment-caused wildfires amplify the need for grid modernizing technologies to enhance safety, reliability, and resiliency of California communities.

2.2.1 BACKGROUND

Since 2006, the CPUC has approved policy frameworks, programs, and investments to modernize the grid. In 2009, the CPUC approved investments in early smart grid

demonstration projects for energy storage; integrated, scalable end-to-end smart grid systems; and dynamic pricing using advanced meters authorized a few years earlier. These projects received roughly 50 percent matching funds from the U.S. Department of Energy (DOE) administered portion of the American Recovery and Reinvestment Act of 2009 in D.09-09-029. That same year the CPUC considered customer direct data access rules per the Energy Independence and Security Act of 2007 in D.09-12-046. Rules for direct and third-party data access, data privacy, and near real time access through home area networks took shape in D.11-07-056 and D.12-08-045 per SB 1476 of 2010 – and were reinforced by Resolution E-4527. These Decisions in the Smart Grid Proceeding (R.08-12-009) worked together with Decisions D.10-06-047, D.12-04-025, and D.13-07-024 pursuant to SB 17 to require the three largest electric utilities to file Smart Grid Deployment Plans and annual reports updating the CPUC on progress made with conceptual and provisional project costs through 2020. With a focus on the impacts on smart customers, smart utility, and smart markets, the deployment plans detail each utility's:

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; and
8. metrics.

Each IOU's smart grid deployment plan's vision statement addresses how a utility will enable customers to become smart customers by: (1) evolving a utility customer from a recipient of energy into a participant in the grid through detailed education and marketing on why the Smart Grid benefits the individual consumer; (2) considering consumer expectations of the Smart Grid, how to meet those expectations, and educating customers to align their expectations with technological realities, drawing on consumer research and past experiences; (3) allowing customers to use electricity more efficiently and save money; (4) supporting smart consumer devices, such as EVs or appliances that can alter operations in response to system conditions or prices; and (5) addressing how the Smart Grid will enable consumers to capture the benefits of a wide range of energy technologies and management services that may, or may not, be offered by the utility, while protecting consumer privacy, and (6) promoting innovation and competition among companies developing new products and services.

In the vision statement section of each IOU smart grid deployment plan, it also describes how the Smart Grid will enable a utility to become a smart utility by operating its electric power transmission and distribution system in ways that anticipate events, enable responsiveness, and permit automatic or "self-healing" responses.

Furthermore, each IOU vision statement states how the Smart Grid will enable the electricity market to become a smart market by: (1) being transparent and providing price, tariff, and usage information sufficient to facilitate demand response and distributed generation; (2) having sufficient communications capabilities to enable and support the reflection of the value of demand response, energy efficiency, distributed generation, and storage in wholesale energy markets; and (3) describing the types of pricing structures needed to ensure cost-effective demand response, distributed generation, and conservation responses benefit customers. Prices play a critical role in the functioning of markets. The smart customer, smart utility, and smart market discussions in the vision statement section of each smart grid deployment plan also state how the Smart Grid will benefit customers and help the utility meet environmental policies already adopted by statute or CPUC action.

The three IOUs filed their Deployment Plans by July 1, 2011 with draft consensus smart grid metrics; the CPUC approved these Deployment Plans in D.13-07-024 on July 25, 2013. Furthermore, the Decision adopted a template and content requirements for annual reports detailing progress and updates to the smart grid Deployment Plans. The IOUs have filed their smart grid annual report providing updates on their Deployment Plans in October of each year since 2012 and were required to do so through October 1, 2020.[21] D.14-05-016 provided energy usage and related data access to local government entities, researchers, and state and federal agencies when such access is consistent with consumer data privacy protections. The CPUC then closed the Smart Grid Proceeding in D.14-12-004 and directed energy usage data issues to be taken up in R.13-11-005.

2.2.2 GRID MODERNIZATION COSTS AND BENEFITS

The CPUC requires the three largest electric IOUs to report on grid modernization costs and associated benefits.

Costs and Benefits | Prospective Estimates from 2011-2020

In 2011, PG&E reported conceptual costs for 2011 to 2015 and provisional costs

[21] Explore all previous annual reports on the CPUC Smart Grid page.

between 2016 and 2020. It reported $800 million to $1.25 billion over the average expected project life of 20 years in capital expenditures and average annual operations and maintenance (O&M) of $25 million to $40 million. This would total $12-$20/year for each customer account.[22] PG&E also anticipated benefits to include: $600 million to $1.4 billion in customer cost savings, $240-$360 million avoided or deferred capital expenditures, and $140-195 million O&M, 1.4-2.1 million tons of CO_2e emissions avoided, and 10-20% system reliability improvement by traditional outage frequency and duration metrics.[23] That same year SDG&E reported preliminary and conceptual costs for 2006-2020 at $3.5 to $3.6 billion,[24] which is roughly $1 billion more than PG&E's cost projections. SDG&E estimated $3.8-$7.1 billion benefits from: $760 million to $1.9 billion societal and environmental benefits from avoided emissions and fuel costs (alternatively 7.7 million tons of CO_2e emissions avoided and 207 million gallons of gasoline avoided), and $3.0-5.1 billion economic and reliability benefits from advanced meters among other Smart Grid investments.[25] SCE reported approved and proposed costs for 2011-2014 and provisional and conceptual cost range for 2015-2020 of $1.87 billion and $486 million to $1.241 billion[26] respectively. While SCE described conceptual costs, it did not estimate the costs. SCE's cost figures are similar in range to SDG&E's. The utility estimated 370 MW of additional demand response (DR) by 2014 to reduce peak costs, 2-6.5% energy consumption reduction for 250,000 megawatt-hours (MWh) avoided per year with DR by 2014, and 700,000-1,400,000 MWh saved per year with voltage reduction once distribution management system upgrades completed and substations automated.

Cost and Benefits | Reporting Period 2019-2020

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22 See PG&E Smart Grid Deployment Plan submitted June 6, 2011 page 155.

23 See PG&E Smart Grid Deployment Plan submitted June 6, 2011 page 169.

24 See SDG&E Smart Grid Deployment Plan submitted June 6, 2011 pages 8, 267, 284, and 338.

25 See SDG&E Smart Grid Deployment Plan submitted June 6, 2011 pages 8, 289-292, 312, and 338.

26 See SCE Smart Grid Deployment Plan submitted July 1, 2011 pages 77-123 and 126-142.

The benefits of California's grid modernization are measured in the 19 consensus metrics: nine on advanced metering infrastructure, one on electric vehicles, one on storage, and eight on grid operations as approved in D.12-04-025. The metrics include:

Advanced Metering Infrastructure Metrics

1. Number of advanced meter (AM) malfunctions where customer electric service is disrupted, and the percentage this number represents of the total installed advanced meters;
2. Number of total megawatts (MW) summer peak load reduced due to smart grid-enabled, utility administered demand response (DR) programs; number of total MW winter peak load reduced due to smart grid-enabled, utility administered DR programs; both by customer class: *Residential, less than 200 or less than 500 kilowatt (kW), greater than or equal to 200 or greater than or equal to 500 kW, and Other (agricultural);*[27]
3. Percentage of demand response (DR) enabled by Automated Demand Response (AutoDR) in each individual DR impact program;
4. Number and percentage of utility-owned advanced meters (AM) with consumer energy monitoring or measuring devices (Home Area Network or comparable devices) registered with the utility – by customer class, CARE status, and climate zone;
5. Number and percentage of time-variant or dynamic pricing tariff customers (by tariff type, customer class, CARE status, and climate zone);
6. Number and percentage of escalated customer complaints related to: 1. the accuracy, functioning, or installation of advanced meters (AM) or 2. the functioning of a utility-administered Home Area Network (HAN) with registered consumer devices;
7. Number and percentage of advanced meters (AM) replaced before the end of

[27] SDG&E divides commercial and industrial (C&I) customer classes at 500 kW while PG&E and SCE divides them at 200 kW. SCE's "Other" customer class includes agricultural and pumping customers.

their expected useful life during the course of one year, reported annually, with replacement explanation;

8. Number and percentage of advanced meters (AM) field tested at customer request pursuant to utility tariffs providing for such field tests; number of advanced meters (AM) tested measuring usage outside CPUC-mandated accuracy bands;
9. Number and percentage of customers using an utility's web-based portal to access energy usage data, enroll in utility energy data programs, or authorize the utility to provide third-party with energy usage data;

EV Metric

10. Number of customers enrolled in time-variant electric vehicle tariffs;

Storage Metric

11. Megawatts (MW) and megawatt-hours (MWh) per year of utility-owned or operated energy storage interconnected at the transmission or distribution level – measured at electricity output terminal;

Grid Operations Metrics

12. The systemwide total number of minutes per year of sustained outage per customer served as reflected by the System Average Interruption Duration Index (SAIDI), major events included and excluded for each year starting on July 1, 2011 through the latest year that this information is available;
13. How often the systemwide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index (SAIFI), major events included and excluded for each year starting on July 1, 2011 through the latest year that this information is available;
14. Number of momentary outages per customer systemwide per year as reflected by the Momentary Average Interruption Frequency Index (MAIFI), major events included and excluded for each year starting on July 1, 2011 through the latest year that this information is available;

15. Number and percentage of customers per year and circuits per year experiencing greater than 12 sustained outages for each year starting on July 1, 2011 through the latest year that this information is available;
16. System load factor and customer class load factor for each year starting on July 1, 2011 through the latest year that this information is available; *(How many times smaller or larger average use is to peak use.)*
17. Number of and total nameplate capacity (MW) of customer owned or operated, grid-tied distributed generation facilities;
18. Total electricity deliveries from customer owned or operated, grid-tied distributed generation facilities, reported by month and by CAISO sub-Load Aggregation Point; and
19. Number and percentage of distribution circuits equipped with automation or remote control equipment, including Supervisory Control and Data Acquisition (SCADA) systems.

The benefits of California's grid modernization are also measured by the environmental, cybersecurity, and other benefit metrics, which were difficult to quantify and left for the IOUs and Energy Division to agree upon later and reexamine as often as necessary. (Table 1) The IOUs reported costs and benefits – both the consensus metrics and the other benefits metrics – in their 2020 Smart Grid Annual Reports.[28]

Each IOU calculates costs as the sum of its total spent annually on grid modernization programs. The IOUs each calculate benefits as a sum of: avoided cost of utility operations, including environmental, customer service, and Transmission & Distribution (T&D); reliability, physical security, and cybersecurity benefits; and demand response

[28] IOUs must report data in alignment with State's Fiscal Year, which corresponds with July 1, 2019 to June 30, 2020.

savings realized in a fiscal year.[29] Each IOU takes a different approach to calculating these grid modernization costs and benefits; thus, the data is not suitable for direct comparison between IOUs.[30] The figures are utility reported figures. See section 4 for additional detail.

Table 1. IOU Estimated Costs and Benefits for July 1, 2019 through June 30, 2020

IOU	Smart Grid Costs[31] ($Millions)	Smart Grid Benefits[32] ($Millions)	Avoided Outage Minutes[33]
PG&E	$235.95	$202.6	81.1 Million
SCE	$67.4	$622.6[34]	219.8 Million
SDG&E	$38.4	$122.5	3.4 Million

29 Benefits may accrue in this reporting period from previously completed projects and should not include all benefits that may be realized over the lifetime of the projects. Some smart grid projects may not have direct benefits, but they may enable other programs or technologies that provide benefits in the future.

30 In some past GRCs, the CPUC reviewed calculation of reliability benefits. However, the estimated benefits figures in this report are as the utilities reported it to the CPUC.

31 Costs per project category/program area can be found in each utility's project deployment section below. SCE invested significantly less in all project categories compared to PG&E except two: distribution automation and reliability and integrated and cross-cutting systems. SCE invested significantly less in the following areas: customer empowerment, transmission automation and reliability, asset management and operational efficiency, wildfire mitigation and resiliency, and security.

32 PG&E's and SCE's avoided outage minutes are the primary driver in the difference in their respective benefits calculation.

33 This year PG&E reported systemwide 1,300 minutes of sustained outage per customer whereas SCE reported 166 minutes and SDG&E reported 125 minutes inclusive of major event days. PG&E customers experienced roughly ten times more sustained outage minutes than SCE and SDG&E. Excluding PG&E's 23 major event days (ME days), SCE's 12 ME days, and SDG&E's 3 ME days, there were respectively 144, 84, and 71 minutes systemwide of sustained outage per customer. (SAIDI) PG&E's average customers systemwide experienced nearly double the frequency of service interruption per year than SCE and triple compared to SDG&E. (SAIFI) PG&E reported 1.57 momentary outages per customer systemwide per year when including major events; SCE, 1.23; SDG&E, 0.26. (MAIFI)

34 According to SCE, its circuit automation program improves reliability from two decades of accruing benefits of deployment. SCE includes their 2019 estimated 219.8 million avoided outage minutes for customer. SCE updated its value of reliability improvement estimate, which calculates the cost of

2.2.3 ONGOING COMMITMENT TO IMPROVE SAFETY AND RELIABILITY

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

Pursuant to Assembly Bill 66 (Muratsuchi, 2013), which directed the IOUs to improve

electric system reliability through greater accountability and enhanced reporting, the CPUC required the utilities to report reliability data on a more local basis in January 2016 Decision D.16-01-008. As a result, the IOUs also annually report the top one percent of their worst-performing circuits and their investment plans for mitigating these reliability deficiency issues. IOUs deploy grid modernizing technologies, such as Geographic Information Systems (GIS) and Outage Management Systems (OMS), to automate and improve outage detection while improving reliability and reporting. Section 3.1.11 of this report dives into the data.

In their GRCs, the IOUs identify wildfire safety among their top priorities and investments. Increasingly, mitigation proposals involve new grid modernization technologies to enhance safety, reliability, and resiliency via monitoring both grid and pipeline operations and distributed energy resources.

With the increase in the number and severity of extreme weather events, the electric utilities must increase their focus on resiliency in addition to reliability. Unlike reliability, which has well-defined quantitative metrics, resiliency is an emerging attribute of the

outages and assigns a value of $2.69 per customer minute of interruption (CMI). Multiplying $2.69 per CMI and 219.8 million customer outage minutes, SCE estimates a savings of $591 million from avoided outage minutes, which represents 95% of the total $622.6 million benefits SCE reported. See SCE Smart Grid Deployment Plan Annual Report 2020 page 9.

grid. Resiliency includes the ability of the electric system to resist failure, reduce the magnitude and/or duration of outage events, and the ability and time to recover from these events.[35] Improving the ability of the system to restore operations fully from a high-stress situation or event is one of the objectives of many grid modernization efforts. Grid modernization initiatives generally enable the utilities to develop situational awareness that anticipates problems using automated fault location technologies and advanced meters. The data from such technologies contribute to operating a more resilient grid by reducing the frequency and duration of outages and enabling local microgrids to operate in island mode[36] to provide electric service during outages.

The rising frequency and potency of catastrophic wildfires in California and the utilities' present-day use of public safety power shutoff (PSPS) events to reduce the incidence of utility equipment-caused wildfires amplify the need for grid modernizing technologies to enhance safety, reliability, and resiliency of California communities. The utilities' wildfire safety related investments include the following wildfire mitigation pathways to guide investments and reduce the negative impacts of PSPS events over the next several years:

1) Reduce Fire Ignitions

   Grid hardening – measures include installing covered conductors and steel poles, and selective undergrounding of distribution and transmission lines currently mounted on wooden poles and towers.

   Proactive operational practices – these include using supervisory control and data acquisition (SCADA) technology to remotely disable reclosing

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[35] In the Climate Change Adaptation proceeding Decision D.19-10-054, the CPUC defines resilience as "the achieved outcome of an adaptation strategy" and resilient as "able to withstand extreme and incremental events and the ability of utility systems to recover when a disruption occurs."

[36] 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.

devices and de-energizing power lines in PSPS events as a last resort to reduce the risk of contact-related ignitions.

Enhanced vegetation management – work includes clearing overhanging branches directly above or near powerlines within a 12-foot radius, and removing trees that are among the highest risk for vegetation-related fires and/or have the potential to hit powerlines if they fall.

Asset inspection and maintenance – tasks include increasing above ground asset inspection with aircrafts (including drones) and crews on the ground, and using GIS and advanced metering infrastructure (AMI) data to monitor facilities for signs of failure.

2) Reduce Fire Spread

The IOUs are installing hundreds of weather stations and high-definition cameras; utilizing satellites, more granular weather forecasts, and remote sensing technologies; monitoring fuel moisture; and running models to predict weather and possible wildfire behavior. The utilities also staff wildfire safety and PSPS emergency operations centers (EOC) around the clock during fire season.

3) Reduce the Number of Customers Impacted by PSPS Events

This includes using distribution sectionalizing/segmentation devices, transmission line switching, and deploying microgrids and backup generation.

4) Reduce PSPS Event Outage Durations

The IOUs aim to reduce the time to restoration post-PSPS event.

5) Reduce PSPS Event Frequency

The IOUs aim to obtain enhanced meteorological data to guide PSPS event decision-making and refine PSPS event boundaries. They seek to install further segmentation devices, microgrids, and additional grid hardening equipment to reduce the frequency of PSPS outages in the future.

3. CPUC GRID MODERNIZATION POLICY DEVELOPMENTS IN 2020 AND POLICY WORK EXPECTED IN 2021

3.1. 2020 POLICY DEVELOPMENTS

Grid modernization related policies approved by the CPUC in 2020 for implementation are in this section; background leading up to this year's actions are provided in each section for context.

3.1.1. DISTRIBUTION RESOURCES PLANS

The CPUC's overarching goals within the Distribution Resource Plans (DRP) 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. Public Utilities Code Section 769[37] required the IOUs to file Distribution Resource Plans (DRPs) by July 1, 2015, proposing contracts, tariffs, or other DER procurement mechanisms to maximize locational benefits and minimize incremental costs of forecasted DERs. Section 769 also required the utilities to identify spending necessary to integrate DERs into distribution planning, modernize their electric grid, and identify barriers to DER deployment. Since meeting California's climate targets involve large increases in electric power demand to decarbonize both the building and transportation sectors, these plans could play an important role in mitigating the impacts of load growth on the distribution and transmission systems in load-constrained areas.

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

Track 1: Locational Analysis/Methodology Issues

Track 1 focused on developing methodologies for two analyses identifying optimal locations for DER deployment; the analyses' methodologies were adopted in D.17-09-026 and implemented in 2018:

1. *Integration Capacity Analysis* (ICA) determines the available hosting capacity of every distribution circuit in each IOU's service territory to accommodate additional DERs. The ICA helps DER developers site projects in grid locations that are less likely to trigger system upgrades. IOUs also use the ICA in the annual distribution planning process to identify upgrades to increase a given area's hosting capacity in light of forecasted DER adoption. The ICA will also be used

[37] Assembly Bill 327 (Perea, 2013) codified as Public Utilities Code Section769.

to streamline the Rule 21 interconnection process for DERs in 2021 as adopted in D.20-09-035.

2. *Locational Net Benefits Analysis* (LNBA). IOUs use the locational net benefits analysis to annually determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid planned traditional distribution system investments. IOUs identify the resulting candidate distribution investment deferral opportunities in annual IOU filings in the DRP DIDF process described below in Track 3, then solicit to procure them through the annual DIDF RFO solicitations for DERs. The LNBA reflects the benefits of DER deployment relative to traditional infrastructure. This data also informs DER sourcing activities determined in the Integration of Distributed Energy Resources and Integrated Resource Planning Proceedings (R.14-10-003 and R.16-02-007 respectively).

These methodologies are currently in use and constantly being improved upon through the DIDF and ICA refinement rulemakings.

Track 2: Deployment Demonstration Projects

In DRP Track 2, the IOUs sought to implement projects with the aim of 1) proving the ability to defer traditional infrastructure projects with DERs, and 2) managing the distribution system with higher DER adoption. Track 2 approved the following demonstration project in 2017, which ended in 2019:

Demo D (operate the system with high adoption of DERs): The Demo D project called for the utilities to integrate high adoption of DER into their distribution operations, demonstrate the operations of multiple DERs in concert, and coordinate operations with third parties and customers. In 2017, this project was approved for PG&E and SCE in D.17-02-007 and D.17-06-012. PG&E's Demo D DER solicitation was unsuccessful because it did not receive cost-effective DER bids. SCE's Demo D concluded in 2019 after SCE determined that the Demo could not be completed because field testing could not be performed due to cybersecurity challenges. Nonetheless, SCE obtained valuable information, such as the design, development, and testing of new control and communication systems for the electric grid.

Demo E (plan and operate a microgrid): The Demo E project sought to demonstrate a microgrid where DERs (both customer- and utility-owned) serve a significant portion of customer load and reliability services. Furthermore, the project aims to demonstrate the use of a DER management system (DERMS), which is a software solution to monitor, control, and optimize both third-party-owned and utility-owned DERs. In 2017, the CPUC approved the microgrid projects for SDG&E and SCE in the aforementioned D.17-02-007 and D.17-06-012, respectively. SCE's and SDG&E's Demo E concluded in 2019. SDG&E utilized their existing Borrego Springs microgrid for this project as a phase two project. SDG&E successfully conducted multiple islanding events, which disconnected the microgrid from the main distribution electric grid with no power interruption to the customers. However, SDG&E encountered challenges islanding when utilizing a third-party owned photovoltaic plant; thus, SDG&E was able to island the Borrego Springs microgrid for only a short period of time. Further updates to the project are available in the SDG&E subsection of IOU Deployments section 4.

Track 3: Integrating DER Adoption Forecasts into System Planning and Investment

DRP Track 3 addressed policy questions related to incorporating new tools and forecast planning methods into existing distribution system planning and investment processes. In 2018, the CPUC adopted:

1. **DER Growth Scenarios and Distribution Load Forecasting**: In D.18-02-004, the CPUC adopted the methodological framework for developing circuit-level forecasts of DER adoption and distribution load to inform distribution planning, as well as supporting process alignment with the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR), IRP, Long-Term Procurement Planning (LTPP), and CAISO's Transmission Planning Process (TPP). Each year the

IOUs disaggregate the CEC IEPR forecast for load and DER down to the circuit level in order to support their August filing of the Grid Needs Assessment (GNA).

2. **Grid Modernization Investment Framework**: In D.18-03-023, the CPUC 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. The Grid Modernization Investment Framework guides CPUC GRC decision-making to help determine the necessary investments to the distribution grid that will yield net ratepayer benefits while modernizing the grid to support high DER adoption and maintaining safety and reliability. In May 2019, the CPUC issued D.19-05-020, which approved $159.2 million in capital expenditures and $11.57 million in operations and maintenance expenses for Grid Modernization in SCE's 2018 Test Year GRC. In December 2020, the CPUC approved $9.275 million in operations and maintenance expenses and $92 million for the Integrated Grid Platform & Grid Modernization Plan in PG&E's 2020 Test Year in D.20-12-005.

3. **Distribution Investment Deferral Framework (DIDF):** The CPUC established DIDF in the 2018 Decision D.18-02-004.[38] DIDF is a planning framework for identifying, evaluating, and selecting opportunities for DERs to defer or avoid traditional distribution investments and produce net ratepayer benefits. The IOUs implemented the framework in 2018, 2019, and 2020, and continue to refine and improve the framework through an annual DIDF reform process. The IOUs submit an annual Grid Needs Assessments and Distribution Deferral Opportunity Report (DDOR) in August of each year, followed by a six-week Distribution Planning

[38] The solicitation framework and key underpinning of the IOUs' annual Grid Needs Assessment and Distribution Deferral Opportunity Report filings are established in the Competitive Solicitation Framework from Decision D.16-12-036 and implemented in the DRP by Ruling on November 19, 2018.

Advisory Group (DPAG) stakeholder process to help screen and vet which planned grid investments are best suited for deferral by DERs via competitive solicitations. Each November, the IOUs file advice letters seeking approval to launch DIDF requests for offers (RFOs) for specific deferral projects.

The CPUC approved over 16 megawatts (MW) of PG&E battery storage contracts and 18.5 MW battery storage contracts for SCE. To date, SDG&E has not had any deferrals. The CPUC also approved the launch of nine DIDF solicitations scheduled for January 2021 where SCE and PG&E will seek DER offers to defer several planned grid infrastructure investments totaling $30.2 million.

3.1.2. DER ACTION PLAN

The CPUC Distributed Energy Resources (DER) Action Plan serves as a roadmap for decisionmakers, staff, and stakeholders working in support of California's DER future, and it facilitates active, coordinated, and forward-thinking development of related DER policy. The CPUC continues to implement its vision to support California's DER future through interrelated CPUC proceedings. Using this framework, the CPUC has completed as of 2020 the majority of 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 2021, the CPUC will be updating the DER Action Plan and may release version 2.0.

3.1.3. IDER

In the Integrated Distributed Energy Resources (IDER) Proceeding R.14-10-003, the CPUC developed and adopted a Competitive Solicitation Framework (CSF) for distributed energy resources (DERs), to provide guidance for the IOUs' competitive solicitations for DERs based on the grid needs identified in the Distribution Resources Plan (DRP) proceeding R.14-08-013. (See 3.1.1 above for more details on DRP.) The

CPUC clarified the relationship between the DRP and IDER proceedings in D.15-09-022, explaining that the two proceedings would work together to create an end-to-end framework to implement Public Utilities Code Section 769.

In October 2020, the CPUC released a staff proposal titled "Distributed Energy Resources Deferral Tariff and Request for Offer Streamlining" for stakeholder comment. The purpose of this staff proposal is to: (1) present DER deferral tariff sourcing alternatives to Requests for Offers (RFOs) with the aim of increasing the number of DER deferral projects based on grid needs identified in the DRP DIDF process; and (2) address issues with the current DIDF annual RFO DER procurement process that increase risk for both DER providers and rate payers. The proposal has three elements: 1) a new DER Tariff focused on aggregation of behind-the-meter (BTM) DERs; 2) a new Standard Offer Contract (SOC) focused on expedited procurement of IFOM DERs; and 3) streamlining of the existing DIDF RFO process to reduce timelines and regulatory burden to improve procurement outcomes. The overall objectives of the staff proposal are to:

1. Streamline and scale up DER deferral procurement;
2. Develop pilots to test the deferral tariff proposals and their elements; and
3. Clarify incrementality policy for DERs sourced for deferral.

A final Decision is anticipated in the first quarter of 2021. If approved, the Staff Proposal will be implemented through the DRP DIDF process starting in 2021.

3.1.4. MICROGRIDS

The CPUC developed policy to facilitate the development of microgrids, which generally include a combination of DERs and are capable of providing energy in the event of a larger grid outage. Recognizing that microgrids may support California's policies to integrate high adoption of distributed energy resources into the electric grid, the Legislature passed SB 1339 (Stern, 2018), which added Sections 8370, 8371, and 8372 to the Public Utilities Code. These new sections are intended to facilitate both the commercialization and interconnection of microgrids.

At its September 12, 2019 Voting Meeting, the CPUC initiated the rulemaking proceeding R.19-09-009, regarding microgrids pursuant to SB 1339 and Resiliency Strategies, to implement its requirements. The scoping memo organized the proceeding into three tracks. In advance of the 2020 fire season, Track 1 developed resiliency plans in areas prone to outage events and wildfires, with the goal of putting some microgrids and other resiliency strategies in place by Spring or Summer 2020. The CPUC approved a Track 1 Decision on June 11, 2020, which focused on:

1. Prioritizing and streamlining interconnection applications to deliver resiliency services at key sites and locations by using pre-approved designs, expediting utility sign-off on projects, and more;
2. Modifying existing tariffs to maximize resiliency benefits by allowing storage to import energy from the grid in advance of PSPS events and removing storage sizing limits for large net energy metering (NEM)-paired storage;
3. Facilitating local government access to utility infrastructure and planning data to support the development of resiliency projects;

4. Approving PG&E's Community Microgrid Enablement Program, and authorizing PG&E's Temporary Generation Program for interim use; and
5. Granting SDG&E's request for a Local Area Distribution Controller.

In Track 2 of the Microgrids OIR, the CPUC focused on fulfilling the legislative intent of SB 1339 by developing standards, protocols, guidelines, methods, rates, and tariffs to support and reduce barriers to microgrid deployment statewide, while also prioritizing system, public, and worker safety, and avoiding cost shifts between ratepayers. The Track 2 Decision was approved January 14, 2021. The Decision (D.21-01-018) focuses on removing barriers to the commercialization of microgrids, directing the utilities to:

1. Revise Rule 2[39] to facilitate IOUs installation of microgrids as special facilities;
2. Revise Rule 18/19 to allow microgrids to at government facilities to serve critical customers on adjacent parcels on a trial basis;
3. Develop a simplified rate schedule for behind-the-meter or single customer microgrids, without shifting costs between customers;
4. Develop a pilot incentive program that would fund clean energy community microgrids to support the critical needs of vulnerable populations; and
5. Develop a pilot program that accelerates evaluation of low-cost, reliable electrical isolation methods.

Within Track 2 of the Proceeding, the CPUC also developed a resiliency framework to guide utilities when reserving temporary generation to serve substation load for the 2021 fire season and on how to transition from diesel temporary generation to cleaner alternatives in subsequent years. Staff released a challenge statement detailing the specific technical and logistical difficulties that arise when powering safe-to-energize load at a substation-level during Public Safety Power Shutoff events. The CPUC also held a workshop in August 2020 attended by vendors, community members, and other

[39] Electric Rule 2 allows utilities, at a customer's request, to install special facilities that provide services beyond those the utility would regularly supply. The customer would pay the cost for these special facilities.

state agencies to discuss diesel alternatives at the substation level. Per the Track 2 Decision, utilities reserving temporary generation are required to submit plans to establish clean substation microgrid projects, which may include pilot projects, as a first step in this transition away from temporary diesel engines.

Track 3 of the proceeding will consider the ongoing implementation of SB 1339 requirements as well as any future resiliency planning. As part of Track 3, CPUC staff convened a Resiliency and Microgrids Working Group, which launched in October 2020. In Track 3, the CPUC plans to further explore the issues identified in the proceeding thus far, which may include but are not limited to: (1) the standardized metrics for measuring resiliency and reliability values, (2) microgrid access to the CAISO wholesale market, and (3) standardizing tariff structures for large multi-customer microgrids. The working group will also consider whether and how potential grid benefits from customer-facing microgrids, regardless of fuel source, may justify modifying standby charges. The topics may be subject to change and reprioritization as discussions evolve over the course of the working group meetings.

Other 2020 Microgrid Activities:

To further advance the CPUC policy framework for commercializing microgrids, CPUC Staff wrote and released a concept paper that classifies various microgrid attributes and value propositions, then describes outstanding regulatory, permitting, financial, and technical barriers to microgrid deployment. The concept paper builds a conceptual basis for Track 3 of the proceeding. The IOUs' 2020 microgrid-related activities are described below:

Pacific Gas and Electric Microgrid Activities

In Track 1 of R.19-09-009, the CPUC authorized three PG&E programs to address immediate resiliency strategies for outages:

1. Make Ready Program, involving infrastructure upgrades that would prepare a subset of distribution substations for the interconnection of microgrid generation resources. The program relates to PG&E's Distributed Generation-Enabled Microgrid Services (DGEMS) initiative, which was cancelled due to concerns over stranded costs and environmental impact, which required further refinement and cooordination with local communities. The DGEMS cancellation caused a reduction in scope of the Make Ready Program.
2. Temporary Generation Program, authorized on an interim basis, reserving third-party mobile generators for deployment during PSPS events to provide power for:
    a. Energizing safe-to-energize substations using temporary interconnection of mobile generation;
    b. Supplying energy for temporary microgrids such as mid-feeder microgrids[40] serving critical facilities or community commercial corridors; and
    c. Providing backup power as a last resort to support continuity of service during public safety power shut-off events to specific critical facilities, such as fire departments, county emergency services, medical facilities, water treatment plants, and major transportation routes.
3. Community Microgrid Enablement Program, developing a framework that would provide utility technical support to enable local communities' efforts to initiate community microgrid solutions. PG&E submitted an Advice Letter describing the Community Microgrid Enablement Program and related tariff in August 2020. The CPUC is currently reviewing the Advice Letter. The PG&E

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[40] A distribution feeder is a line that feeds electricity from a substation drawing from the bulk power system into a subset of distribution lines that power residential, commercial, and/or agricultural ratepayers along the distribution grid. When a distribution feeder feeds power from a substation in/through a High Fire Threat District to a ratepayer-populated area, an IOU installs switches to turn the connection on and off in the middle of the feeder, adds a place to interconnect DERs, then operates a mid-feeder microgrid to power the populated area that is safe to energize.

program would treat a microgrid as a collection of standard grid resources whether it is islanded or connected to the larger grid, and the program will offer funding for some of the grid upgrades necessary for the microgrid.

PG&E is developing temporary mid-feeder microgrids to safely provide electricity to community resources by isolating a section of a distribution line from the wider grid (islanding the area) and re-energizing it using mobile generation during an outage. PG&E's mid-feeder microgrid approach is operational in at least six locations as of the 2020 wildfire season, while a total of 40 locations were proposed in PG&E's 2020 General Rate Case filing. These mid-feeder microgrids are:

- Hardened,[41] central subsets of the local electric distribution system that serve "Main Street" (central business district);
- Potentially quickly (within 1 hour) isolated/islanded from the broader grid during PSPS events by on-site PG&E workers;
- Powered with mobile generators using a pre-installed interconnection hub for rapid energization; and
- Approximately $1 million each, not including site preparation costs.

PG&E also intends to consider installation of remote grids in lieu of maintaining and/or rebuilding overhead pole lines, where cost effective. In December, PG&E submitted an Advice Letter seeking approval for supplemental customer contracts that would facilitate remote grid projects. For example, this solution may be feasible in small portions of the Butte County grid infrastructure that may need to be rebuilt or hardened following the 2018 Camp Fire. In the design phase, remote grids are presently described as stand-alone, self-sufficient grids powered by solar, battery energy storage, and propane generators or other technologies to serve small electric

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[41] See pages 22 and 36 for the definition of hardening / hardened.

distribution systems. The sites are chosen based on risk evaluation and cost analysis, with consideration of alternate mitigation options, such as:

- Proactive de-energization of power lines (PSPS events);
- Undergrounding; and
- Hardening in place (e.g. wood to steel poles, covered conductors).

Southern California Edison Company Microgrid Activities

SCE is engaged in collaborative research with University of California, Los Angeles on reducing customer impacts from PSPS events using microgrids, according to the September update on SCE's Wildfire Mitigation Plan. SCE anticipates completing the first phase of this study in early 2021.

San Diego Gas and Electric Company Microgrid Activities

In its Track 1 submittal to R.19-09-009, SDG&E reported several microgrid projects could be in-service by end of 2020. These projects involve microgrid installations proposed for Cameron Corners, the Ramona Air Attack Base, and Desert Circuit 221. SDG&E also currently operates a microgrid at Borrego Springs.

In Track 1 of R.19-09-009, the CPUC approved SDG&E's request for a Local Area Distribution Controller, which is a software and hardware solution that enables the distribution grid operator to monitor, manage, and control the component resources of the microgrid. SDG&E is currently implementing the contract for this controller as it applies to all the microgrid projects listed above.

SDG&E is also developing a new model for evaluating microgrids as a PSPS event mitigation measure, according to the September update to its Wildfire Mitigation Plan.

3.1.5. INTERCONNECTION

The Rule 21 tariff sets interconnection, operation, and metering requirements for generation facilities connecting to a utility's electricity distribution system in order to maintain safety and reliability of the distribution and transmission systems. The CPUC's

Interconnection Rulemaking, R.17-07-007, addresses barriers to the deployment of distributed energy resources (DERs), considering policy and programmatic changes to streamline the interconnection process for distributed energy resources. The March 2018 Working Group One Report surfaced urgent interconnection issues. The October 2018 Working Group Two Report leveraged work on the integration capacity analysis (ICA) from the DRP Proceeding R.14-08-013 to further streamline the Fast Track interconnection process[42] in Rule 21. The July 2019 Working Group Three Report outlined the consensus and non-consensus items across the eleven interconnection issues, which addressed: (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) the interconnection of electric vehicles. These reports set the stage for Working Group Four, which began meeting in February 2020 and filed its final Working Group Four Report on August 12, 2020. The report put forth further consensus and non-consensus proposals addressing anti-islanding requirements[43], interconnection processes to facilitate implementation of California Zero Net Energy building codes, and the implementation of Distributed Energy Resource Management Systems (DERMS).

Informed by these working group reports, the CPUC adopted two major Decisions within R.17-07-007 to date. First, on March 28, 2019, the CPUC issued D.19-03-013, based on input from Working Group One to improve the Rule 21 interconnection process as follows:

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

[43] Anti-islanding capabilities ensure that, if a fault occurs on the distribution system, any DERs connected to the system quickly de-energize so that a portion of the distribution grid does not unintentionally remain energized (forming an "unintentional island"). Unintentional islands are of great concern because they can result in (1) safety hazards for personnel, (2) out-of-phase conditions and transient voltages and frequencies, which can damage equipment, and (3) other abnormal conditions, including reduced fault current capability, which can reduce the system operator's ability to clear faults and return the circuit to normal operation.

- Clarify and simplify specific technical screens applied to projects interconnecting via the Fast Track process;
- Require the utilities to publish standard requirements and cost tables for various metering configurations, especially for solar plus storage systems;
- Specify the process by which Fast Track projects may change project details during the interconnection process;
- Determine the level of additional study required before already-interconnected project facilities may modify facility characteristics; and
- Develop a pathway for continued consideration of lower cost, more widely applicable telemetry requirements, which allow utility visibility into distributed generation.

On September 24, 2020, the CPUC approved a second Rule 21 Decision (D.20-09-035), based on input from Working Group Two and Three Reports, as well as recommendations from the Vehicle-to-Grid Alternating Current Interconnection subgroup.[44] The Decision improves and updates Rule 21 in order to maximize the renewable energy generation that can be safely integrated with existing grid infrastructure, establish a path forward for vehicle to grid interconnection, and streamline and automate the interconnection process as follows:

- Incorporate Integration Capacity Analysis (ICA) results[45] into the interconnection process to: (1) determine where and when existing circuits can accommodate additional distributed generation without requiring distribution upgrades and (2) allow interconnecting resources to export up to those limits;

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[44] The Vehicle-to-Grid Alternating Current Interconnection subgroup was authorized in R.17-07-007 and R.18-12-006 to discuss and identify existing standards to fulfill safety requirements for the interconnection of a mobile inverter housed inside the electric vehicles. The subgroup met between September and December of 2019 and filed a final subgroup report in both proceedings on December 6, 2019.

[45] The Integration Capacity Analysis (ICA) tool was developed in the Distribution Resources Plan Proceeding, R.14-08-013. More information on the tool is available in section 3.1.1 of this report.

- Define the required specifications for generating facilities to be considered non-export,[46] limited export, or inadvertent export, and address concerns regarding the high cost of the current relay options by approving the use of less costly electronic power control systems;
- Clarify which rules and interconnection processes apply to electric vehicles, including those capable of exporting power to the grid;
- Establish a temporary exemption from smart inverter requirements for alternating current vehicle to grid pilots;
- Streamline the interconnection application process by: (1) expanding the Fast Track interconnection process to projects of all sizes, (2) allowing systems smaller than 30 kilowatts, as well as non-export systems, to bypass unnecessary technical screens, and (3) permanently adopting all process improvements identified in the non-exporting energy storage pilot;
- Require the IOUs to hold a workshop on improving their interconnection portals, including the implementation of 18 specific subproposals that were identified by Working Group Three and the implementation of proposals for automating the tracking of V2G projects; and
- Provide transparency by: (1) requiring the IOUs to track 19 timeline parameters, with the goal of meeting timelines for 95% of Large NEM and Non-NEM interconnections within 30 months, and (2) establishing standard construction timelines for grid upgrades related to interconnection and for the installation of Net Generation Output Meters.

The CPUC is expected to address the Working Group Four issues in a forthcoming decision.

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[46] Non-export generating facilities are sized such that the generator output is used for onsite load only; they are designed to prevent the transfer of electrical energy from the generating facility to the electric distribution grid.

3.1.6. SMART INVERTERS

Inverters convert direct current (DC) to alternating current (AC) power and are essential for interconnecting various distributed energy resources (DERs), such as solar PV systems (which generate DC power), to the grid. Smart inverters can be an essential aspect of integrating DERs by providing critical support to the distribution grid that was historically provided by traditional fossil fuel resources, including voltage and frequency support.

Smart inverters also have the potential to improve operation of the grid through their advanced communications and control capabilities. Under the CPUC's direction, the Smart Inverter Working Group (SIWG) developed inverter functionality recommendations that are being incorporated into the Electric Rule 21 tariffs. The Working Group's 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. 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 modern grid operations. With full operationalization of the requirements adopted through 2020, these smart inverter functions will increase the amount of DER generation that the grid can accommodate, potentially mitigate some distribution infrastructure upgrades, and increase grid safety and stability.

Smart Inverter Phase 1 and 2 Functions

Starting in 2017, the IOUs incorporated seven autonomous Phase 1 smart inverter functions into their Rule 21 tariffs.[47] The CPUC also approved Phase 2 Smart Inverter

[47] CPUC Decision D.14-12-035 in R.11-09-011.

communications requirements into Rule 21 in April 2017, which took effect in June 2020.[48] Currently, all inverter-based generation interconnecting under Rule 21 now must be capable of communications via prescribed pathways; the Institute of Electrical and Electronics Engineers (IEEE) standard 2030.5[49] serves as the default protocol used by IOUs to communicate to either individual DERs, energy management systems, or DER aggregators. Additional work is required before these communications capabilities can be fully operationalized, including the development of cybersecurity protocols and the build-out of IOU communications infrastructure such as DERMS. To this end, the SIWG began a series of meetings on cybersecurity requirements for DER communications in August 2020; this series of meetings will continue into 2021.

Smart Inverter Phase 3 Functions

In April 2018, the CPUC approved revisions to Rule 21 that incorporate smart inverter Phase 3 advanced functions.[50] By June 2020, a majority of the Phase 3 advanced functions were adopted as required functionalities for all inverter-based DERs interconnecting under Rule 21. These advanced functionalities, such as "Monitor Key Data" and "Scheduling Power Values and Modes," once operationalized with communications capabilities, will increase utility visibility into grid conditions and allow DERs to respond to dynamic grid needs.

In addition to the cybersecurity requirements, the SIWG commenced an ongoing series of meetings in August 2020 to review recent updates to nationally recognized inverter standards and update Rule 21, as necessary, to leverage these developments.

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[48] In April 2017, CPUC Resolution E-4832 approved the Rule 21 tariff changes ordered in D.16-06-052 regarding smart inverter communications requirements from Phase 2.

[49] IEEE standard 2030.5 is also known as the Smart Energy Profile (SEP) 2.0 Application Protocol Standard.

[50] In April 2018, CPUC Resolution E-4898 approved the Rule 21 tariff changes ordered in D.16-06-052 regarding smart inverter advanced functions from Phase 3.

These meetings will continue into 2021 and help California's smart inverter requirements reflect best practices in DER integration.

Parallel to the work of the SIWG, the Interconnection Rulemaking, R.17-07-007, leveraged newly available smart inverter capabilities to facilitate the interconnection of DERs. CPUC Decision D.20-09-035 updated Rule 21 to integrate newly available smart inverter capabilities into the IOU interconnection processes and allow the use of non-default smart inverter settings, where possible, to avoid the need for grid upgrades.

3.1.7. ENERGY STORAGE

The CPUC's energy storage procurement policy furthers three primary goals:

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

AB 2514 (2010)

In response to AB 2514 (Skinner, 2010), the CPUC established energy storage procurement targets in 2013 of 1,325 MW to be procured by 2020 and operational by 2024. In 2020, the CPUC approved 1,207 MW of new energy storage resources, the highest amount of energy storage procurement approved in a single year. To date, the CPUC has approved procurement of more than 2,900 MW of new energy storage capacity to be built in the state. As of January 2021, there is about 706 MW of storage operational in the CAISO markets. The AB 2514 storage mandate includes three distinct grid domain sub-targets with some flexibility between the grid domain targets. Cumulatively, the utilities' procurement to date exceeds the 1,325 MW target and satisfies nearly all domain-specific requirements. See Table 2 below for more detail including the grid domains and targets.

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

	Grid Domains	AB 2514 Storage Procurement Mandate Targets (MW)	AB 2514 Storage Procurements (MW)	Other Storage Procurements (MW)*	Procurement that meets Mandate (MW)**	Transferred (MW)**	Adjusted Excess or Deficiency with CPUC Allowances (MW)**
PG&E	Transmission	310	85	557	642		229.88
	Distribution	185	30	52.88	82.88	102.12	0
	Customer-Side	85		64.1	64.1		-20.91
SCE	Transmission	310	0	120	120		0
	Distribution	185	27	292.08	319.08	190	0
	Customer Side	85	100	253.34	170	55.92	29
SDG&E	Transmission	80		110	78.85		-1.15
	Distribution	55		43.65	43.65		-11.35
	Customer-side	30		30	30		
	IOUs Total	1,325	242	1,407.28			

As of November 2020: ** CPUC rules allow limited substitution between domains to meet targets. Procurement related to System Reliability Authorization (D.19-11-016) is not included in this table.

The utilities procure energy storage to meet local capacity requirements. Energy storage is also a focus of distribution planning, deferral, and other services. Thus, energy storage increasingly serves as a crucial backbone of grid modernization efforts and a reliability resource of choice.

AB 2868 (2016)

On May 8, 2017, the CPUC issued D.17-04-039 which adopted a process to implement AB 2868 (Gatto, 2016). The legislation requires the IOUs to propose programs and investments for up to 500 megawatts (MW) of distribution level storage with an allowance of up to 25% of the procurement for BTM storage. This Decision requires each utility to propose investments for up to 166.66 MW of distributed energy storage systems in their 2018 energy storage procurement and investment plans. Such investments had to achieve the following objectives:

1. Accelerate widespread deployment of distributed energy storage systems to achieve ratepayer benefits;
2. Minimize overall costs to ratepayers and maximize overall benefits;
3. Prioritize programs and investments that provide distributed energy storage systems to public sector and low-income customers;
4. Not unreasonably limit or impair the ability of non-utility enterprises to market and deploy energy storage systems; and
5. Reduce petroleum dependence and GHG emissions as well as meet State air quality standards.

On June 27, 2019, CPUC Decision D.19-06-032 authorized PG&E to create a new electric water heating thermal program (referred to as "WatterSaver"), adding up to 5 MW thermal energy to the grid for $6.4 million in response to PG&E's proposed 2018 energy storage procurement and investment plan. This decision also rejected the IOU's remaining AB 2868 customer program proposals due to lack of details about project design and insufficient documentation of benefits to ratepayers. The CPUC provided guidance for filing a revised application should the IOUs choose to reapply.

When implemented in 2021, PG&E's WatterSaver program will optimize the performance of program-enrolled heat pump water heaters and electric resistance water heaters, using management systems to generate benefits for customers and the grid. These "smart" performance management systems control when the program-enrolled water heaters draw energy from the grid and when they store heated water to achieve load shifting that results in peak energy savings and reduced reliance on petroleum. CPUC approved the "WatterSaver" program with modifications requiring PG&E to provide additional program reporting to demonstrate its compliance with the AB 2868 objectives and requiring cost-effectiveness tests and measures for distributed generation. The CPUC approved the final program details in Resolution E-5073.

As part of its 2020 Energy Storage Procurement and Investment Plan, Southern California Edison (SCE) proposed two AB 2868 customer programs, which are the New Home Energy Storage Pilot (NHESP) and the Smart Heat Pump Water Heater Program (SHPWHP). The proposed NHESP, if approved, would add 12 MW of energy storage to the distribution grid with $5 million of ratepayer funding and serve 2,581 homes. This pilot would provide a "mid-stream" incentive to zero net energy (ZNE) housing developers, so they install battery storage systems that achieve GHG emission reductions, meet air quality standards, provide grid benefit, prioritize low-income customers, and lower customer bills overall. Although ZNE homes are not required to use storage, a CPUC study found that adding storage can mitigate some of the grid integration costs expected from high adoption of solar PV resulting from ZNE policy. The pilot targets housing developers, instead of homeowners or property managers, to determine if it would be more cost effective.

The SHPWP is modeled after PG&E's Watter Saver program. If approved, it would add management control systems to up to 17,000 heat pump water heaters in SCE's service territory for $13.9 million. The CPUC, along with stakeholders, are currently evaluating SCE's proposed AB 2868 customer programs through a public proceeding. The CPUC recently issued a ruling in the proceeding requesting input on modifications to SCE's AB 2868 programs to ensure the programs: (1) generate benefits to both customers and the grid; (2) target disadvantaged communities and customers; and (3) are cost-effective. Specifically, the ruling requests SCE perform the cost-effectiveness tests outlined and mandated for distributed generation programs through D.09-08-026 and D.19-05-019.[51]

[51] D.09-08-026 approved a cost-effectiveness framework for SGIP and other distributed generation (DG) technology programs, and ordered DG programs to calculate the Participant Cost, Total Resource Cost (TRC), and Public Administration Cost (PAC) tests for program evaluation. See D.09-08-026's Attachment A. D.19-05-019 requires the TRC, PAC, and Ratepayer Impact Measure (RIM) tests be used in all cost-effectiveness analyses effective July 1, 2019. These tests include the Total Resource Cost, Program Administration Cost, and Ratepayer Impact Measure Cost tests.

In January 2021, the CPUC also issued a Proposed Decision authorizing approval of PG&E's application for procurement and cost recovery of Local Area Reliability Services Agreements to procure 43.25 megawatts (MW) and 173 megawatt hours (MWh) of energy storage capacity for $21.3 million in support of a larger CAISO transmission reliability project referred to as the Oakland Clean Energy Initiative (OCEI). This will enable PG&E to meet the local resource adequacy needs during peak electricity demand hours at this location after an aging gas peaker plant shuts down. The OCEI reliability package of transmission upgrades and energy storage resources is two-to-three times less expensive than the alternatives of building new transmission lines or building new fossil generation plants in a dense urban area already affected by urban pollution.

3.1.8. TRANSPORTATION ELECTRIFICATION

Transportation electrification takes critical steps towards achieving California's ambitious climate goals of reducing greenhouse gas emissions below 40 percent of 1990 levels by 2030 and achieving carbon neutrality by 2045. California also aims to have 5 million light-duty[52] zero emission vehicles on the road by 2030 and 250,000 electric vehicle charging stations operational by 2025. Additionally, Governor Newsom established the intention for the state to stop sales of new gasoline-

[52] Light-duty refers to passenger vehicles (cars and light trucks) and all other vehicles under 8,500 pounds.

powered vehicles by 2035[53] through a recent Executive Order. To date, there are approximately 763,800 light-duty zero emission vehicles on the road in California. Beginning with the Smart Grid Proceeding, R.08-12-009, the CPUC began exploring the potential for plug-in electric vehicles (PEV) to interact with an increasingly modernizing grid. The CPUC's policy activities related to PEVs categorize into four broad policy goals and work streams:

1) Determining and approving electric rates, both commercial and residential, to encourage EV charging at times that are beneficial for the grid and for renewables;
2) Approving programs and policies for the IOUs to deploy EV charging infrastructure for light-duty and medium/heavy-duty EVs;
3) Designing rebates and incentives for the deployment of EV charging infrastructure, including incentives for purchasing EVs in the case of Low Carbon Fuel Standard (LCFS) revenue; and
4) Addressing policy to encourage vehicle-grid integration (VGI) or the ways in which EVs can provide grid services.

In December 2018, the CPUC issued a rulemaking (R.18-12-006) regarding transportation electrification, the Development of Rates and Infrastructure for Vehicle Electrification (DRIVE) Rulemaking, which directed the utilities to develop EV rates that are affordable and beneficial to the grid. The CPUC also directed staff to develop a framework to guide future IOU investments in transportation electrification. In response, the CPUC released the draft Transportation Electrification Framework (TEF) in February 2020. The TEF directs the IOUs to develop ten-year plans for their transportation electrification investments, addressing topics including: certain cross-cutting issues; needed upgrades to the electrical grid to support PEVs; managing charging load; and alignment with other planning processes like the IRP, DRP, and those at the CEC, CARB, and CAISO. The CPUC has been reviewing party comments

[53] Governor Newsom issued Executive Order N-79-20 on September 23, 2020.

on the draft TEF throughout 2020, in addition to holding workshops on many of the topics covered.

Time-Variant Rates and EVs

Time-variant rates include time-of-use, dynamic, and real time rates. Time-variant rates send price signals that encourage EV charging at times that are more beneficial to the grid such as when there is lower overall demand. In 2019, the CPUC approved a new PG&E commercial time-variant EV rate. Pursuant to this decision, PG&E submitted an Application to the CPUC for a dynamic commercial EV rate in Fall of 2020, which the CPUC is now reviewing. This dynamic rate intends to better account for grid impacts in the future.

In April 2020, the CPUC authorized SDG&E to temporarily offer a residential time-of-use rate (TOU-M rate) to commercial EV customers adopting EVs or installing public EV charging stations. This served as a bridge while the CPUC reviewed SDG&E's application for an EV-specific commercial rate. In December 2020, the CPUC approved an EV-specific commercial rate for SDG&E to implement, adding SDG&E to ranks of utilities that offer their own commercial EV rates like SCE and Liberty Utilities.

For residential customers, PG&E, SCE, SDG&E, and Liberty Utilities each continue to offer EV time-of-use energy rates to encourage off-peak EV charging. SDG&E is also implementing a Public Grid Integrated Rate for use at DC fast charging stations the utility owns while Bear Valley implements an EV Pilot Rate. [54]

Charging Infrastructure Deployment

In August 2020, the CPUC authorized a new charging infrastructure program, SCE's Charge Ready 2. This is the largest single-utility EV charging program in the country, with a budget of up to $436 million to fund approximately 37,800 EV chargers. This program also includes requirements for load management plans and demand

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

response (DR) program participation. The CPUC continues to oversee implementation of pilots for schools and beaches across the three large IOU territories, a medium- and heavy-duty vehicle electrification program in SDG&E territory, and a pilot program called EV Empower, which provides residential chargers to low- and medium-income customers in PG&E territory.

The CPUC also continued to oversee: (1) the implementation of light-duty EV charging infrastructure programs at SDG&E,[55] SCE,[56] and PG&E[57] that will deploy up to 13,500 charging stations at multi-unit dwellings, workplaces, and some public locations,[58] as well as (2) programs authorizing the large IOUs to install charging for medium- and heavy-duty vehicles. The CPUC is currently evaluating an application from SDG&E to expand its light-duty infrastructure pilot, Power Your Drive.[59] SDG&E requested to spend $43.5 million to build 2,000 additional Level 2 charging ports for light-duty vehicles at apartment buildings and workplaces. A decision on this application is required by March 1, 2021 pursuant to AB 841 (Ting, 2020).

A 2012 settlement between the CPUC and NRG – a large U.S. energy company that was connected to the 2000 California Energy Crisis – is now completely implemented and a final audit is underway. The settlement directed NRG to spend $102.5 million to deploy EV charging infrastructure to support apartment buildings and workplaces, public DC fast charging, pilot programs for research and development (R&D), and pilots to support transportation electrification in underserved communities. In addition to some of the load management strategies described above, the NRG Settlement

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55 Learn more about D.16-01-045.

56 Connect with more knowledge D.16-01-023.

57 Plug into D.16-12-065.

58 The actual amount of deployed infrastructure will almost certainly be lower than 13,500, however the final charging station count is not yet known since the IOUs are either still implementing or concluding these pilots.

59 A.19-10-012

also tested vehicle-to-grid technologies and energy storage integration as load management strategies.

Vehicle-Grid Integration

Vehicle-grid integration (VGI) focuses on using EVs to provide grid services by acting as a battery that can support the grid or charging at specific times. To do this, EVs must have capabilities to manage charging or support two-way interaction between vehicles and the grid. As part of the effort to develop VGI programs the three large IOUs developed pilots that test using energy meters specifically for EV charging (separate from the house's meter) to help drivers save on fuel costs, allow them to enroll in TOU rates while keeping their homes on tiered rates, and allow EV drivers them to avoid paying to install a new utility meter just for their EV. Building on the 2019 CPUC public workshop discussing the results of the Plug-In Electric Vehicle Submetering Pilot, in 2020, the CPUC directed the IOUs to commence work on drafting a Plug-In Electric Vehicle Submetering Protocol for submission by December 2020. A Proposed Decision on submetering is expected in 2021.

In 2020, the CPUC also issued a decision clarifying the status of EV charging service providers as public utilities. The decision holds that the providers of medium- and heavy-duty EV charging services, and off-road EV charging services are not public utilities, and requires SCE and PG&E to modify their Electric Rule 18. This may have the efficient impact of allowing shared medium- and heavy-duty EV charging.

The CPUC, along with other state agencies, is developing policies to support Vehicle-Grid Integration (VGI), which is discussed further in the interconnection section 3.1.5 of this report. The CPUC issued a decision on VGI, implementing SB 676, in December 2020.

3.1.9. DEMAND RESPONSE

Demand response (DR) programs provide financial incentives to customers to reduce or shift their demand for electric power at times when it is beneficial to the grid either because overall demand is very high or wholesale market prices are high. Demand response programs can also help integrate renewable resources by shifting electric power demand to times of day when renewable generation is high.

First, there are demand response programs that IOUs bid as resources into CAISO's wholesale energy markets (also known as "supply side" demand response resources).

These programs include emergency reliability programs as well as programs that are used when wholesale energy prices are high. Then, there is the Demand Response Auction Mechanism (DRAM) pilot, which provides a pathway for third-party DR providers and their customers to bid demand response resources into CAISO's wholesale energy markets (also a "supply side" demand response resources).

In response to the CPUC's 2019 DRAM Evaluation Report, the CPUC changed the design of the DRAM pilot to improve performance and reliability of DRAM resources and extended the DRAM pilot for four years (2020-2023).[60] Changes included more accurate estimates of DR resource capacity (MW), a more sophisticated DR capacity payment structure that penalizes underperformance, and minimum resource dispatch activity requirements. The IOUs conducted DRAM auctions for 2020 and 2021 and procured 216 MW and 206 MW (August capacity) from third-party DR providers.

The CPUC held several DRAM Working Group sessions in 2020 to discuss a variety of potential refinements to DRAM, some of which were adopted in a Resolution to apply to the DRAM auctions for 2022 & 2023. Currently, Nexant Inc., a consultant, is conducting a follow up evaluation of the DRAM pilot. Its evaluation report is expected to be available in the fourth quarter of 2021.

As an alternative to the DRAM pilot, the CPUC established a Load Impact Protocol review process to qualify third-party DR providers to provide DR capacity that may fulfill electric resource adequacy (RA) to non-IOU load serving entities (LSEs), such as community choice aggregators and energy service providers. In 2020, three third-party DR providers successfully completed the review process and qualified to offer DR capacity of up to 217 MWs in 2021 to non-IOU LSEs.

In alignment with the state's focus on reducing GHG emissions, the CPUC prohibited the use of customer-owned fossil fuel generators during DR events as of January 1, 2019, and launched an associated verification mechanism with a device, which the

[60] D.19-07-009 and D.19-12-040 approved these DRAM decisions.

IOUs studied for effectively detecting customer compliance. The CPUC is currently considering whether devices should be required on the generators as part of a verification mechanism.

Since demand response resources participate in CAISO wholesale electricity markets, the CPUC evaluated DR resource performance in the 2020 Extreme Heat Wave Root Cause Analysis. In response to the 2020 rotating outages caused by an extreme heat storm from August 14 through 19, the CPUC jointly prepared the Final Root Cause Analysis Report, which examined the condition and events of August 14 and 15, 2020, including the performance of demand response resources during the heat wave using customer meter settlement data. The analysis indicated that while some DR resources performed well and helped mitigate grid reliability issues, other DR resources underperformed or were not utilized by the CAISO market. Work continues toward fully understanding the underlying issues and developing policy solutions. The final report also provided recommendations for immediate, near, and longer-term improvements to statewide electric power resource planning, procurement, and market practices, some of which will involve DR. Those recommendations are now under consideration in the Summer Reliability rulemaking for preparation prior to summer 2021. More details on demand response next steps are provided in grid modernization policy work expected in 2021 (Section 3.2).

3.1.10. ENHANCED ELECTRIC RELIABILITY REPORTING

Enhanced electric reliability reporting provides an objective standard and information to foster continuous improvement of reliability. Pursuant to the goals of AB 66, which directs the IOUs to improve electric system reliability through greater accountability and enhanced reporting, the CPUC issued D.16-01-008 to consolidate previous reporting requirements and provide the IOUs with a template to facilitate more granular reporting of electric reliability metrics in a single report. The CPUC also directed IOUs to report on the top one percent of their worst-performing distribution circuits and annually detail their investment plans for mitigating these reliability deficiencies. Several IOU-deployed grid modernizing technologies, such as Geographic Information Systems (GIS), Advanced Distribution Management System (ADMS), Fault Location, Isolation, and Service Restoration (FLISR), and Outage Management Systems (OMS), aim to mitigate reliability concerns as well as automate and improve outage detection while improving reporting.

D.16-01-008 directed the utilities to use an enhanced reliability reporting template to annually report the previous year's reliability data to the CPUC on July 15 beginning in 2016.[61] Reliability data is reported at the utility service territory aggregate level as well as the more local division or district level.[62] D.16-01-008 requires the IOUs to identify their top one percent of worst performing circuits based on two or three years of outage duration and outage frequency data. Further, the IOUs must identify worst performing circuits that appeared on previous years' lists and report on ongoing remediation efforts. The three IOUs report one percent of their worst-performing circuits, while PacifiCorp, Liberty Utilities, and Bear Valley Electric Service report their top three, two, and one worst performing circuits, respectively.

D.16-01-008 also allows customers to request reliability information about their circuits via utility websites and receive responses in a timely manner. All the IOUs must also conduct at least one annual public, in-person town hall and webinar presentation about the information in their annual electric reliability reports.[63] Furthermore, in compliance with D.16-01-008, the IOUs developed a joint proposal to consolidate different reliability-reporting requirements from CPUC Decisions and General Orders into a single reporting framework.

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61 Browse Electric System Reliability Annual Reports.

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

63 Due to the ongoing impacts of COVID-19, PG&E, SCE, and SDG&E submitted a joint request to the CPUC asking for relief from the requirement of hosting in-person reliability reporting meetings. These meetings would instead be hosted online only until such time as restrictions on in-person gatherings are lifted.

California IOU Reliability Metrics Compared to Median US Reliability Performance Metrics

In 2019, SCE's and SDG&E's electric reliability performance for total outage duration per customer was better (lower) than the national median, while PG&E's was worse (higher) underperformed (*see Table* 3). All the IOUs in California performed better than the national median for outage frequency per customer (*see Table* 3). However, all IOUs performed worse than the national median for outage duration per event in their service territory (*see Table* 3). National data is based on the U.S. Energy Information Administration's (EIA) Annual Electric Power Industry Report. This report details data from 770 electric companies that reported duration of outages, 709 electric companies that reported frequency of outages, and 709 companies that reported event duration.[64]

Table 3 compares the electric reliability indices of PG&E, SCE, and SDG&E with the national electric reliability indices' median values.

Table 3. IOU Electric Reliability Compared to the U.S. National Median Values for 2019

Reliability Measure	Nation (Median)	PG&E	SCE	SDG&E
Duration per Customer (Minute/Customer)	99.8	117.7	90.8	68.6
Frequency per Customer (Event/Customer)	1.1	1.0	0.9	0.6
Duration per Event (Minute/Event)	95.4	116.5	104.8	115.2

Source: EIA Annual Electric Power Industry Report 2019

64 The reliability indices excluded major event days, planned outages, and ISO outages.

Enhanced reliability reporting supports the State's grid modernization efforts by increasing transparency into the reporting metrics for reliability standards and requiring the IOUs to publicly describe the remediation efforts they plan to take to address the worst performing circuits. It also allows any customer or community to understand local reliability in their area and efforts to improve reliability in underperforming circuits. The reliability reports may serve as an assessment tool to measure the progress of grid modernization investments and deployments on the improved grid reliability goal and security improvement objective of SB 17 and Public Utilities Code Sections 8360 through 8369.

3.1.11. CUSTOMER DATA ACCESS

Click-Through Authorization Process Expansion

The click-through authorization process is an online authorization process that allows customers to easily authorize their utility company to share the customer's energy data with third-party demand response providers, which can use the data to help the customer optimize their demand response performance. The CPUC is currently considering IOUs' applications to expand and improve the click-through process in application proceedings A.18-11-015, et. al. The IOU proposals include:

- Expanding the click-through authorization process to DER and energy management providers;
- Making improvements to the click-through authorization process;
- Improving the data delivery process;
- Offering an alternative click-through authorization process; and
- Delivering the expanded data set within ninety seconds.

3.1.12. EPIC REAUTHORIZATION

The Electric Program Investment Charge (EPIC) supports the development of new, emerging, and pre-commercialized clean energy technologies in California. These projects must be designed to produce electricity ratepayer benefits in the form of increased reliability, improved safety, and/or reduced electricity costs. Under Phase 1 of Rulemaking R.19-10-005, in 2020 D.20-08-042 renewed EPIC through 2030. In Phase 2 of this proceeding, the CPUC continues to consider the role and budgets of the three EPIC investor-owned utility administrators for the 2021-2030 period, as well as other policy and administrative updates.

EPIC Decision Context

While the California Energy Commission and/or the IOUs administer EPIC, the CPUC oversees and monitors the implementation of the ratepayer-funded program. Effective January 1, 2012, D.11-12-035 required PG&E, SCE, and SDG&E to institute the EPIC surcharge to fund renewables and research, development, and deployment (RD&D) programs in the ratepayer and public interest. Ratepayers contributed $185M to EPIC in 2020. To date, the CPUC allocated more than $1 billion to fund over 500 EPIC projects.

D.12-05-037 directed the CEC, PG&E, SCE, and SDG&E to administer the EPIC funds, with the utilities directed to focus solely on technology demonstration and deployment (TD&D) programs. The Decision required EPIC administrators to file coordinated triennial investment plans to the CPUC for consideration. The plans are required to map planned investments to the electricity system value chain, including grid operations/market design; generation; transmission; distribution; and demand-side management. The Decision also requires that EPIC administrators address how the principles articulated in Public Utilities Code Sections 740.1 and 8360 related to grid operation and smart grid systems are applied in their investment plans. This Decision established the EPIC program to continue from 2013 through 2020.

Grid-focused EPIC Projects

EPIC projects administered by the utilities are intended to provide ratepayer benefits related to the state's transmission and distribution grid. These projects fall broadly into four categories: (1) integration of renewables and distributed energy resources into the grid; (2) grid modernization and optimization; (3) customer focused products and services, including integration of Demand-Side Management for grid optimization; and (4) cross-cutting efforts to better prepare and respond to natural disasters and support next generation infrastructure. The utility administrators continue these projects.

EPIC 2020 Accomplishments

In 2020, the EPIC administrators continued previously approved EPIC RD&D projects. The CPUC also reauthorized EPIC for 10 more years, from 2021-2030. The CPUC granted the request of the EPIC Administrators to change the investment plan cycle from three years to five years and authorized an adjustment for inflation for the second five-year investment plan.

3.2. GRID MODERNIZATION POLICY WORK EXPECTED IN 2021

Below is a list of some of the grid modernization projects anticipated in 2021:

- **Distribution Resources Plan** – In January 2021, PG&E will launch a 2021 Distribution Investment Deferral Framework (DIDF) Request for Offers (RFO) solicitation to procure DERs to defer seven planned investments with a value of $20.3 million and a capacity of 24.5 MW. SCE will hold a similar solicitation to defer two planned investments with a capacity of 9.6 MW. Deferral solicitation results from the 2020 DIDF cycle will be submitted summer 2021 for CPUC approval. Additional refinements are expected for the 2021 DIDF cycle through the annual reform process. The annual IOU Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) filings are currently scheduled to occur on August 15; these filings will identify planned grid investments that are potential candidates for deferral. The annual Distribution Planning Advisory Group will reconvene from September through October 2021 to vet the candidate deferrals and the IOUs will submit candidate distribution investment deferral opportunities to the CPUC for approval in November 2021. Additionally, improvements to streamline the DIDF RFO solicitation process will be implemented according to the Integrated Distributed Energy Resources (IDER) Decision approved in February 2021. The Decision adopts the staff proposal for a DER Tariff and Standard Offer Contract. These new DER sourcing methods will be piloted starting in 2021 and incorporated into the DIDF process.
- **DER Action Plan** – The CPUC will consider updating the DER Action Plan in 2021 as most of the action elements have been completed since its adoption in 2016. Many of the vision elements of the 2016 plan remain relevant to the CPUC today, but they need to be refined and augmented to guide and coordinate DER policy to align with CPUC priorities in transportation electrification,

advanced rates and tariffs, equity, resiliency, modernization of grid infrastructure, DER market integration, and DER program integration.

- **IDER** – A Decision in February 2021 approved the "Distributed Energy Resources Deferral Tariff and Request for Offer Streamlining" staff proposal. Please see section 2.1.3 above for background. Implementation of the new DER sourcing methods will begin in preparation for the start of the 2021 DIDF. The DER tariff pilot will focus on soliciting aggregations of behind the meter (BTM) DER customers to defer planned grid investments. To date, only in front of the meter (IFOM) storage has been awarded contracts for distribution deferral services. The pilot tests whether BTM DERs can successfully defer utility grid upgrades for the first time.
- **Microgrids** – In 2021, the Microgrids OIR R.19-09-009 will continue implementing SB 1339, considering more complex topics like in front of the meter (IFOM) microgrids and the value of resiliency. The utilities will then submit Advice Letters to implement approved proposals in Track 2, which include tariff changes and a new microgrid incentive program. CPUC staff will continue to facilitate the Resiliency and Microgrids Working Group, which will guide the ongoing implementation of SB 1339 and future resiliency planning.
- **Interconnection Rule 21** – In 2021, the CPUC is expected to consider a decision addressing the recommendations of Rule 21 Working Group Four, which concern anti-islanding requirements, interconnection processes to facilitate implementation of California Zero Net Energy building codes, and the implementation of Distributed Energy Resource Management Systems (DERMS). Phases 2 and 3 of the proceeding, which will address rate-setting issues and small and multi-jurisdictional utility issues, will commence after the Working Group Four Decision is issued. In addition, the CPUC will review the IOUs implementation of significant updates to Rule 21 adopted in the 2019 and 2020 Decisions.

- **Smart Inverters** – In 2021, the Smart Inverter Working Group (SIWG) will provide recommendations on: (1) cybersecurity requirements necessary to securely operationalize smart inverter Phase 2 communications requirements, and (2) updates to smart inverter requirements to reflect 2020 nationally recognized smart inverter standards updates. In addition, the SIWG will convene to develop technical specifications for the final two smart inverter advanced functions in Phase 3, which will allow DERs to respond to and help stabilize local voltage fluctuations. These functions will facilitate the deliverability of distributed energy storage capacity. These advances in smart inverter policies, in aggregate, will increase the amount of renewable generation the grid can accommodate without upgrades and contribute to grid safety and stability.
- **Energy Storage** – CPUC staff anticipate continued high levels of storage resources achieving commercial operation as a result of AB 2514, as well as CPUC Decision D.19-11-016, which require 3,300 MW of electric system reliability procurement for 2021-2023. The CPUC anticipates undertaking a formal evaluation of California's energy storage framework as envisioned by the decisions that originally implemented AB 2514.
- **Transportation Electrification** – The CPUC will continue to provide the IOUs direction on transportation electrification investments and planning needed to support future grid upgrades to achieve California's ambitious EV adoption goals. The CPUC will also refine policies to enable EV charging to benefit the grid at lower cost to drivers, such a submetering protocols and implementation of new electric rates designed for commercial EV chargers. Moreover, in 2021, the CPUC will continue to work closely with other state agencies on implementation of legislation such as AB 841, Executive Orders focused on EV adoption, data collection, and other collaborations.
- **Demand Response** – CPUC staff will hold workshops to discuss further refinements to DRAM per D.19-07-009. The utilities will conduct a new DRAM solicitation in February to procure DR from third parties for delivery in 2022. An independent

consultant will evaluate the performance of the DRAM pilot; the evaluation report is anticipated in the fourth quarter of 2021. In the emergency Summer Reliability Rulemaking (R.20-11-003) currently in progress, the CPUC is looking to expand demand response resources as well as improve the performance of existing programs to provide reductions in electricity demand. Parties have proposed a new DR program for emergency load reduction and several changes to existing DR programs to help reduce demand during future heat waves. The CPUC may adopt some of these proposals for implementation by this summer.

- **Enhanced Electric Reliability Reporting** – The CPUC will continue to work on ways to better track and assess system upgrades related to improving reliability of electricity as well as understanding potential customer equity impacts of unreliable electric service. Pursuant to D.16-01-008, the six California electric investor-owned utilities are required to submit annual reliability reports that include key metrics for their service territory as a whole as well as districts.
- **Customer Data Access** – In early 2021, the CPUC is anticipated to vote on a Decision regarding the IOUs' applications to expand and improve the click-through customer data access process in active proceedings (A.18-11-015, et. al). The IOUs propose to:
    - Expand the click-through authorization process to DER and energy management providers;
    - Make improvements to the click-through authorization process;
    - Improve the data delivery process;
    - Offer an alternative click-through authorization process; and
    - Deliver the expanded data set within 90 seconds.

  The potential benefits of the proposed improvements include streamlining the processes for: (1) customers to authorize service providers to access their data and (2) utilities to transfer customer data quickly and efficiently to such authorized DER and energy management service providers.

- **General Rate Cases –** The CPUC will complete its review of SCE's GRC for 2021 Test Year and begin review of PG&E's GRC for Test Year 2023 upon filing. The SCE GRC includes several proposed grid modernization-related investments; the PG&E GRC may also include grid modernization related investment proposals.
- **EPIC** – In 2021, the CPUC will monitor CEC's one-year interim plan. The EPIC Renewal Proceeding anticipates a staff paper on options for improving EPIC administration and recommendations for addressing several administrative issues identified in the 2017 EPIC program evaluation.

4. IOU GRID MODERNIZATION DEPLOYMENT IN CALIFORNIA

4.1. BACKGROUND

In smart grid annual reports filed each October, utilities report their grid modernizing project updates relative to their 2011 smart grid deployment plan (SGDP) through 2020, in addition to estimated project-related benefits and costs, electric system risks, and the consensus metrics to capture progress on policy goals in compliance with the statutes and Decisions. Utilities use the template and meet content requirements using the categories below:

- Customer Engagement and Empowerment;
- Transmission and Distribution Automation and Reliability;
- Asset Management and Operational Efficiency;

- Cyber and Physical Grid Security; and
- Integrated and Cross-Cutting Systems.

This section of the report contains select grid modernization related utility programs, projects, and pilots from July 1, 2019 to June 30, 2020, in each utility's subsection below. More projects can be found in each IOU's complete 2020 annual report available on the CPUC's report website.

4.1.1 DEPLOYMENT PROJECT BENEFITS

The IOUs report annually on their progress with grid modernization projects, quantify the monetary costs and benefits of their investments, and report policy goal-supportive metrics established in D.12-04-025. Grid modernization benefits may be realized over different years than the year project costs are incurred, thus costs and benefits don't necessarily align when reported for a single year. While the methodology for calculating project benefits among the three IOUs varies, all of the utilities factor reliability benefits as the largest monetary benefit..

In prior years, each utility reported estimating its own reliability benefits using value of service (VOS) reliability estimates that inform the customer interruption cost model developed by Lawrence Berkeley National Laboratory (LBNL). This model monetizes reductions in customer minutes of interruption (CMI) achieved through fault location isolation and service restoration (FLISR) and other distribution automation technologies.[65] While PG&E and SDG&E use the same model base for estimating their reliability benefits, their estimated value of service (dollars per CMI) each differ. SCE estimates a value of $2.69 for each avoided CMI; neither PG&E nor SDG&E submitted

[65] 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.

this figure this year, which prevents readily calculating the portion of the reliability benefit dollars reported that directly link to CMI monetization.

Furthermore, the utilities have different methodologies for estimating the number of avoided outage minutes that have been obtained through the deployment of grid modernizing technologies. As shown in Table 2 in section 2.2.2, SCE estimated 219.8 million avoided CMI in 2020, which is nearly three times higher than PG&E's estimated 81.1 million avoided CMI, despite both utilities serving a similar number of customer accounts in similarly sized service territories.[66] As a consequence of SCE's higher estimate for avoided CMI relative to the other IOUs, SCE's calculated reliability benefits figure is three times larger than comparably sized PG&E reported and six times larger than smaller sized SDG&E reported. PG&E's benefit figure is almost double SDG&E's. As shown in Table 2, the utilities reported both costs and benefits as estimated to have been spent and accrued from July 1, 2019, to June 30, 2020. This timeframe is the 2020 IOU annual report period for progress updates on the IOUs' smart grid deployment plans.

According to the IOUs' annual compliance reports, smart meter deployments continue to provide value during the reporting period. Advanced meters enable instant meter reads for the design and use of time-variant rates, demand response, EV sub-metering, and more. The utilities also reported benefits to customers, energy markets, and the utility from automation projects. Automation projects lay a communication foundation to the grid with software and/or algorithms, so resources can participate in CAISO's energy markets and give greater control to the utility over

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[66] 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 $2.63 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.

maintaining their assets. Environmental benefits related to the integration of renewable energy generation resources, both centralized and distributed, as well as those related to electric vehicle load, were noted. Other identified benefits relate to operations, reliability, and demand response/energy conservation.

1. **Customer Empowerment**

The IOUs consider customers as an integral, prominent driver of grid modernization projects. They aim to provide customers with information, such as energy usage patterns, rate options with or without price signals, energy conservation ideas, and peak-load reduction options. Customers may thus be empowered with knowledge and options to manage their energy use and costs, including using time-variant rates. Applications and tools evolve to meet customers' communication preferences and expectations. This category consists of projects that deliver information, services, and controls that enable customers to take advantage of demand response systems, time-variant and dynamic pricing, and programmable smart devices.

2. **Transmission and Distribution Automation/Utility Operations**

Projects in the Transmission Automation and Reliability (TAR) and Distribution Automation and Reliability (DAR) category improve the utilities' information, monitoring, analysis, early detection, and control capabilities on both the transmission and distribution levels of the electric grid. TAR projects provide wide-area monitoring, communication, protection, and control tools necessary to monitor bulk power system conditions; safely and reliably integrate utility-scale (IFOM) intermittent generation resources; and prevent emerging risks and threats to transmission system stability. Similarly, DAR projects provide the ability to safely and reliably integrate high levels of distributed energy resources on the distribution level, including intermittent generation load supply as well as the increasing load demand of EVs. Like TAR projects, DAR projects also detect and isolate faults, provide "self-healing"[67] benefits, and optimize voltage and reactive power (VAR) to maintain power quality and decrease energy loss. TAR and DAR projects deliver a modern grid with the infrastructure necessary to support the integration of all types of DERs at scale.

3. **Asset Management, Safety, and Operational Efficiency**

Grid modernization projects in this category enhance grid asset monitoring, operation, and optimization capabilities for more efficient grid operations and asset management. These projects enable the utilities to use near real time asset condition data to manage the maintenance and replacement of grid infrastructure on a health basis rather than on a time-in-service basis, which may minimize critical equipment failure and/or premature costs. Thus, the utilities report that these projects help the IOUs manage costs associated with maintaining and replacing equipment.

4. **Cyber and Physical Grid Security**

Physical and cybersecurity are paramount to full development, implementation, operation, and management of a modern grid. Physical and cybersecurity investments are becoming more important as the utilities install SCADA, communications, and other automation systems on their entire transmission and distribution grid. These systems modernize the grid and have the potential to increase reliability risks of the electric grid if the system risks are not preventatively managed against all potential risk vectors in concert with ever advancing technology and the IOUs' relevant teams. The risk-based security programs of the IOUs enhance security throughout their networks by preparing the network to detect and defend against internal and external attacks, tracking access (establishing attribution and nonrepudiation of all system activities and logging such data), optimizing operational network connections for speed and needs, and more. All such projects must be

[67] 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.

implemented in compliance with the Cybersecurity Framework from the National Institute of Standard and Technology (NIST) and Critical Infrastructure Protection (CIP) Standards from the North American Electric Reliability Corporation (NERC), which the Federal Energy Regulatory Commission (FERC) adopted.

5. Integrated and Cross-Cutting Systems

Integrated and cross-cutting systems projects 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 overall grid systems efficiently deliver benefits across IOU operations and to customers. RD&D programs such as EPIC open the doors for new system integrations to be piloted, scaled, and even patented. Integrated communications systems provide solutions to enable sensors, metering, maintenance, and grid asset control networks to seamlessly communicate and better serve customers. In the long run, 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. As part of integrated and cross-cutting systems projects, workforce development and advanced technology training will also enable the successful deployment and use of new technologies, which will maximize the value of these technology investments. Furthermore, achieving and exceeding supplier diversity goals as part of grid modernization projects ensures that California's diverse workforce and businesses contribute to building California's grid of the future.

In this reporting period, SDG&E's progress per project in each program area varied. While Customer Empowerment/Engagement had no new project progress, four of the six program areas (Transmission Automation and Reliability; Distribution Automation and Reliability; Asset Management, Safety, and Operational Efficiency; and Integrated and Cross-Cutting Systems) had grid modernization projects that made progress. SDG&E's Security program area takes a risk-based approach and is by far the category with the highest total spend, but SDG&E does not provide a public report.

SCE's progress for projects in each category also varied. While SCE included no progress on Security projects, six of the seven types [Customer Empowerment; Transmission Automation and Reliability; Distribution Automation and Reliability; Asset Management, Safety (Wildfire Mitigation and Resiliency), and Operational Efficiency; and Integrated and Cross-Cutting Systems] provide project updates. They note their approach to Security is transforming from "security by obscurity" to systems design coupled with a common services architecture, so as to effectively integrate modern cybersecurity into SCE, its modernizing grid, and its edge devices. SCE takes a risk-based approach, employing NIST Cybersecurity Framework and NERC CIP standards. The utility architects its networks to isolate the electric grid operations network from its internet-facing office networks, segment them, centrally monitor them, encrypt data, implement access control systems , and coordinate grid operations unit with cybersecurity threats, among other measures. SCE profiles, authenticates, monitors, detects, and defends devices and/or users to implement access control systems, which is standard practice for cybersecurity. SCE submitted neither total spend nor a public report; however, data may be found in their GRCs.

PG&E's progress for projects in each program area in the reporting period varied from complete deployment to on target for completion. PG&E exclusively provided updates on projects in all seven project categories (Customer Empowerment and Engagement; Distribution Automation and Reliability; Transmission Automation and Reliability; Asset Management, Safety, and Operational Efficiency; Wildfire Mitigation and Grid Resilience; Security; and Integrated and Cross-Cutting Systems).

4.1.2 ADVANCED METERING INFRASTRUCTURE DEPLOYMENT

Table 4. Electric Advanced Metering Infrastructure (SmartMeters / SmartConnect) Installed[68]

IOU	Total Advanced Meters Activated	Advanced Meter Opt-outs[69]	Percentage of Opt-outs	Annual Escalated Customer Complaints[70]
PG&E	5,281,640	42,718	0.81%	1
SCE	5,177,109	17,095	0.33%	367
SDG&E	1,482,231	5,717	0.39%	0
Total	11,940,980	65,530	0.55%	368

Source: IOU 2020 Smart Grid Annual Reports and Data Requests

In 2006, the CPUC approved IOUs to begin full deployment of Advanced Meter Infrastructure, which was largely completed in 2013. The IOUs currently install and may increasingly install more advanced meters and/or submetering devices to accommodate transportation electrification as required by statute, Executive Orders, and CPUC Decisions. Advanced meter opt-outs refer to electric meters of customers who remain in the service territory and have either declined to adopt smart meters or returned to using analog meters. For SDG&E, it also includes advanced meters without radio frequency reading capability. The percentage of opt-out meters relative to the total number of advanced meters has remained less than one percent for all IOUs.

68 These statistics only include data as reported by the investor-owned electric utilities in their recent Smart Grid Annual Reports. The investor-owned gas utilities have also deployed millions of advanced meters also known by proprietary names. For SCE, installed meters are activated meters as opt-out customers use entirely different meters.

69 Advanced meter opt-out totals listed here are since the beginning of the advanced meter programs. PG&E's cumulative opt-out figure is as of December 31, 20220. SDG&E's point-in-time opt-outs represent the number of advanced meter that are manually read, including advanced meters without radio frequency reading capability, as of September 24, 2020; it is not a cumulative number.

70 Escalated complaints are customer complaints regarding advanced meters that have gone through the complaint process and reached resolution during the reporting period.

Annual escalated advanced meter customer complaints have decreased and remain relatively low.

4.2. 2020 IOU GRID MODERNIZATION DEPLOYMENTS

4.2.1. SAN DIEGO GAS & ELECTRIC (SDG&E)

This section highlights select SDG&E's 2020 grid modernization deployment projects and provides SDG&E's estimated expenditures and benefits realized between July 1, 2019 and June 30, 2020.

Costs

Table 5. SDG&E's Estimated Grid Modernization Costs[71] (Fiscal Year July 1, 2019 through June 30, 2020)

Program Areas	Total Spent
Customer Empowerment and Engagement	$0
Distribution Automation and Reliability	$5,533,000
Transmission Automation and Reliability	$7,578,000
Asset Management, Safety, and Operational Efficiency	$3,608,000
Security	$21,187,000
Integrated and Cross-Cutting Systems	$511,000
Total Estimated Costs	$38,417,000

[71] Total estimated cost is based on total spend, including operations and maintenance (O&M) and capital expenditures, excluding Contribution in Aid of Construction (CIAC), and net of grant-based reimbursements from the California Energy Commission (CEC) and Department of Energy (DOE).

Benefits

Table 6. SDG&E's Estimated Grid Modernization Benefits[72] (Fiscal Year July 1, 2019 through June 30, 2020)

Benefit	Estimated Value
Reliability Benefits	$58,980,000
Physical and Cybersecurity Benefits	$12,274,000
Customer Demand Response Benefits	$628,000
Avoided Costs – Operational, Capital, Environmental	$50,635,000
Total Estimated Benefits	$122,517,000
Avoided Outage Minutes	3,354,828

Projects

Highlights of SDG&E's FY 2019-2020 grid modernization deployment projects include:

- SDG&E submitted grid modernizing technologies as wildfire mitigation technologies in its 2020 Wildfire Mitigation Plan. These projects include advanced application of Phasor Measurement Units/Devices as transmission falling conductor protection in high risk fire zones and other Wide Area Monitoring Protection and Control (WAMPAC) applications.
- SDG&E customers connected nearly 23,000 new NEM distributed generation (DG) systems (primarily rooftop solar), which is 7,000 fewer systems than last year, bringing the total to 185,535 interconnected DG systems and nearly 1,414 MW NEM DG capacity;
- SDG&E commercial/industrial customers connected 6.9 more MW BTM energy storage this reporting period compared to 9.6 MW last reporting period. Since its start in May 2016, SDG&E installed a total of more than 28 MW of commercial

[72] SDG&E's total estimated benefits is based on a benefits evaluation model from EPRI's 2010 report. SDG&E estimates economic benefits, reliability benefits (based on LBNL's value of service reliability model), and environmental and societal benefits (based on an EDF-SDG&E developed model). Project benefits may be realized over different years than costs.

BTM storage on its grid. Residential customers connected nearly 15 more MW BTM energy storage in this reporting period for a total of over 35 MW.

- SDG&E is working on four solar and/or storage microgrids to provide resilient power to critical facilities and affected communities during PSPS events: Cameron Corners, Ramona Air Attack Base, Butterfield Ranch, and Shelter Valley. They are not yet in service.
- SDG&E expanded EV charging infrastructure by installing 145 new EV charging ports through their programs and 9 new charging ports on their campus. Though many continue to work from home during the pandemic, the total employee owned EVs is now 711. They reported the same estimated 11,000 EV growth number as last year, which brings the region to nearly 53,000 EVs.
- SDG&E purchased nearly 41% of goods and services from diverse suppliers in core business areas such as electric engineering & construction, gas operations, and clean transportation. This exceeds the 21.5% foundational goal and represents over $635 million.

Featured Projects

- **Distribution Interconnection Information System (DIIS)** – Since 2013, the information system directly supports distributed energy resource (DER) projects applying for net energy metering (NEM). The DIIS upgraded in Phase 4 to verify third-party provider license numbers, add customer protection guide language, include smart inverter communication complaint along with a certification checkbox to import solar inverter and battery inverter data from the CEC, provide optional audit trail document upload, and gather financial institution name if financed.
- **Borrego Springs Microgrid** – As one of two grid modernizing microgrid projects SDG&E launched in 2012, the Borrego Springs microgrid project sought to establish a microgrid demonstration at an existing substation to evaluate the effectiveness of integrating multiple types of DERs, feeder automation system technologies, and outage management system (OMS) with advanced controls

and communications. SDG&E now plans to use more energy storage rather than the two 1.8 MW diesel generators as grid-forming devices in phase three (2020-2023). It also plans to upgrade the microgrid controller for more functionality and reliability in dynamic energy need scenarios. The original project proved the effectiveness of a microgrid islanding one of three circuits on a 12kV distribution system. Phase two expanded the microgrid to island the entire community of 2,500 residential and 300 commercial and industrial customers during the day and serve critical loads at night. The 14 MW peak load microgrid currently islands the entire distribution substation of three circuits (one 69 kV tie line and two 12.5 MVA transformers feeding three 12 kV circuits), using one 6MVAr capacitor bank at 12 kV for Var control, third-party 26 MW PV array, two 1.8 MW diesel generators, and two substation batteries (1.5MW, 4.5MWh total). SDG&E's annual report did not include information about the four other microgrids included in its highlights.

- **Phasor Measurement Units/Devices (PMU)** – According to the U.S. Department of Energy, these monitoring devices measure instantaneous voltage, current, and frequency at specific locations on the grid. PMUs provide that data fast (over high speed internet) on GPS synchronized time in multiple formats, which helps utilities "see" system conditions and depict a sequence of events. PMUs are also called synchrophasors because they provide near-real time synchronized phasor measurements. These are among the smart grid deployment plan investments that are now part of the Wildfire Mitigation Plan proposals. They support nearly instant de-energization with millisecond accuracy for timed operations and are installed with related software for fire hardening projects. In the reporting period, PMUs cost nearly $11 million for both transmission and distribution projects.
- **Electric Program Investment Charge (EPIC)** – SDG&E leveraged ratepayer-funded EPIC projects to evaluate and test new technologies and uses of data before deploying them into grid operations. SDG&E's pre-commercial EPIC

demonstration projects focus on: Advanced Distribution Automation, Advanced System Operations, Safety and Wildfire Mitigation, Renewable and Distributed Energy Resource Integration, Energy Storage, and Grid Modernization and Optimization. This year SDG&E completed and filed comprehensive final project reports on its five EPIC-1 and six EPIC-2 cycle projects. This year, SDG&E has four EPIC-3 cycle projects underway to: (1) use AMI data for advanced utility system operations, (2) simulate safety training with augmented visualization, (3) fly unmanned aircraft systems (UASs) with advanced image processing for grid inspections and operations, and (4) experiment with multipurpose mobile batteries for the Port of San Diego among other applications. SDG&E continues to collect 8.8% of the annual budget from ratepayers, or a $13.7 million annual budget from 2012 to 2014, $15 million annual budget from 2015 to 2017, $16.3 million annual budget from 2018-2020, and $13 million annual budget from 2021 to 2025.

4.2.2. SOUTHERN CALIFORNIA EDISON (SCE)

This section provides information on SCE's grid modernization deployment projects and estimated expenditures and benefits realized during the reporting period.

Costs

Table 7. SCE's Estimated Grid Modernization Costs[73] for Fiscal Year July 1, 2019 through June 30, 2020

Project Types	Total Spent
Customer Empowerment	$3,611,934
Distribution Automation and Reliability	$46,699,963
Transmission Automation and Reliability	$1,240,304
Asset Management and Operational Efficiency	$4,048,053
Safety via Wildfire Mitigation and Resiliency	$2,939,692
Security	SCE did not include.
Integrated and Cross-Cutting Systems	$8,909,691
Total Estimated Costs	$67,449,637

Benefits

Table 8. SCE's Estimated Grid Modernization Benefits for Fiscal Year July 1, 2019 through June 30, 2020

Benefits	Estimated Value
Reliability Benefits[74]	$591,326,402
Physical and Cybersecurity Benefits[75]	SCE did not quantify.
Customer Demand Response Benefits[76]	$8,571,660
Avoided Costs – Operational and Environmental	$22,745,177
– Capital	SCE did not identify.
Total Estimated Benefits	$622,643,239
Avoided Outage Minutes	219.8 Million

Projects

Highlights of SCE's FY 2019-2020 grid modernization deployments include:

- SCE migrated its 4,491,118 residential customers to default TOU rate structures beginning in October 2020 as planned and approved in CPUC D.19-07-004. Prior to default TOU rates, 486,269 customers used TOU rates and the largest TOU rate participating customer class was Commercial and Industrial under 200 kW customer accounts with 853,436 on TOU rates;
- SCE received approval of a $378 million budget to build out its transportation electrification infrastructure and deployed 598 charge ports at 28 workplace, multi-family dwellings, fleet parking, and/or destination center customer sites by June 2020;
- SCE installed 220 remote control switches (RCS) and 285 remote sectionalizing reclosers (RSR) in order to automatically and/or remotely restore power to customers after fault-caused outages;
- SCE puts dissolved gas analysis (DGA) units and bushing monitoring devices to monitor transformer condition online and quickly de-energize a troubled transformer. In the reporting period, SCE has 58 DGA units in service on 26 220kV

[73] Cost figures are SCE reported numbers.

[74] 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 changed how reliability improvements are calculated from distribution automation and how those improvements are valued through updating its VOS estimates while using elements of DOE's methodology. Other utilities have not similarly updated their VOS estimates. The modified approach significantly increases the calculated reliability benefits relative to past reports. (2019 Smart Grid Annual Deployment Plan Update and SCE Smart Grid Annual Report filed October 1, 2020 pages 3 and 8). This point is provided as SCE reported it.

[75] SCE identifies the category as including avoided impacts of physical and/or cybersecurity related incidents, but does not quantify physical and cybersecurity enhancement benefits. See SCE Smart Grid Annual Report filed October 1, 2020 page 8.

[76] SCE states, "Demand Response and Energy Conservation benefits are specifically attributed to demand response enabled by Auto-DR technology and controllable programmable communicating thermostats for SCE's PTR-ET-DLC program." See SCE Smart Grid Annual Report filed October 1, 2020 page 8.

A transformers and 14 500kV AA transformers throughout 12 substations. SCE will have 34 more DGA units in service by the end of 2020 on 10 220kV A transformers and eight 500kV AA transformers at six substations.

- SCE's Distribution System Efficiency Enhancement Program (DSEEP) services expand SCE's wireless communication system (NETCOMM), which allows SCE to use their radio communication infrastructure to remotely monitor and control SCE's distribution automation devices. This year, SCE added 4,058 distribution automation devices and added 17 infrastructure radios to communicate with new devices, specifically radio-controlled switches (RCS), new capacitor banks (NCB), and automated recloser (AR). SCE also maintained existing radio infrastructure devices, replacing 819 automation devices, maintaining 313 packet radios, and replacing 1,061 end of life battery-backed radios.

Featured Projects

- **Demand Response Systems** – Delivering demand response (DR) resources involves many systems, including customer and vendor notification, load control dispatch, event status webpages, customer enrollment and reporting, and DR bidding platforms. In 2020, SCE enhanced its DR systems by migrating its control platform to the cloud in December. SCE also prepared all DR systems and processes to align with SCE's new company-wide customer relationship and billing system: Customer Service Re-Platform Project (CSRP).

- **Energy Storage** – SCE piloted the Distribution Energy Storage Integration (DESI) Program in 2013 with DESI 1. These projects aim to better understand energy storage use cases, performance, and cost-competitiveness as the operating environment changes, threats to the system increase, and technologies advance. In 2020, SCE has seven battery energy storage systems remaining in the program: DESI 1, DESI 2, Mercury 1-4, and Gemini 1. DESI 1 and 2 have become capable of autonomously monitoring conditions and discharging real and reactive power to support high demand conditions. Both are preparing for CAISO market participation by making communication and architecture updates. Mercury 4 tests voltage regulation and PV dependability while increasing circuit DER hosting capacity. The storage project has 11.5 MW of NEM PV that delivers up to 8 MW of reverse power flow during the day. Once operational in 2021, Gemini 1 will support the Poole Hydro Plant and allow islanding on the 16kV Strosneider circuit if the 115kV feeder line disconnects from the bulk power system. The reservoir level at Poole and BTM solar PV support Gemini 1 in islanding mode. Gemini 1 will also use lessons learned for operations under cold weather conditions.

- **Volt/VAR Controls** – Capacitor controls remotely operate switched capacitor banks on the distribution system. Capacitors charge and discharge electric charge for brief periods to support voltage and VAR; this prevents customer electronics damage and safety hazards. In 2020, SCE deployed 400 programmable capacitor controls (PCC) to replace failing capacitor controls. This works in concert with the Distribution Volt/VAR Control (DVVC) implemented at 300 substations to coordinate and optimize voltage and VARS across all circuits the substation feeds, expanding DER potential.

4.2.3. PACIFIC GAS & ELECTRIC (PG&E)

This section shares PG&E's grid modernization deployment projects and estimated expenditures and benefits realized between July 1, 2019 to June 30, 2020.

Costs

Table 9. PG&E's Estimated Grid Modernization Costs for Fiscal Year July 1, 2019 through June 30, 2020

Project Category	Approximate Cost
Customer Empowerment and Engagement	$48,460,000
Distribution Automation and Reliability	$49,890,000
Transmission Automation and Reliability	$41,400,000
Asset Management, Safety, and Operational Efficiency	$22,460,000
Wildfire Mitigation & Grid Resilience	$42,680,000
Security	$21,300,000
Integrated and Cross-Cutting Systems	$9,760,000
Total Estimated Costs	$235,950,000

Benefits

Table 11. PG&E's Estimated Grid Modernization Benefits – Fiscal Year July 1, 2019 through June 30, 2020

Benefits	Estimated Value
Customer Reliability Benefit[77]	$199,000,000
Direct Customer Savings – Bill Forecast Alerts, Demand Response[78]	$372,000
Avoided Costs – Operational, Capital, Environmental[79]	$3,200,000
Total Estimated Benefits	$202,572,000
Avoided Outage Minutes[80]	81.1 million

[77] PG&E calculates customer reliability benefits figure using the Value of Service calculator with changes related to tax law and wildfire risk index disabled FLISR circuits. The figure derives from

Projects

Highlights of PG&E's FY 2019-2020 grid modernization deployments include:

- 63,186 residential customers use time-variant EV rate plans. According to PG&E, this equals 22% of total registered EVs in the service territory to date. It also equals 1.2% of their activated customer meters.
- Temporary Microgrids (TMG), formerly known as Resilience Zones, provide energy resiliency during PSPS events by keeping electric service on in central community areas when the broader area is deenergized. PG&E TMGs feature: (1) circuit isolation devices to isolate the local circuit from the de-energized grid and (2) a pre-installed interconnection hub (PIH) to rapidly connect temporary generation to power the isolated circuit as an energized, islanded microgrid. PG&E's first TMG operated in 2019 in Angwin, California. In the reporting period, PG&E constructed four TMGs, three more are in construction, and 10 others are designed.
- PG&E had six active, one closing, and three launching EPIC RD&D projects during this reporting period. The IOU completed 34 EPIC projects to date and patented two technologies developed – one for an algorithm that detect unauthorized PV interconnections and another for a mobile meter with modular housing/board assembly.
- PG&E's Modular Protection Automation and Control (MPAC) buildings are pre-engineered, pre-fabricated, and standardized turnkey substation protection, automation, and control systems to facilitate full SCADA monitoring, data

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calculating the monetary benefits of avoided customer outage minutes, customer minutes of interruption (CMI), and customers experiencing sustained outages (CESO) savings (tracked per event) achieved through FLISR on its circuits.

78 PG&E had the same figure for direct customer savings last year.

79 PG&E has Environmental developments in PG&E's Corporate Sustainability Report.

80 PG&E uses FLISR to calculate CMI, CESO, and avoided outage minutes.

integration, and control of the substation's assets from a remote location. PG&E deployed MPAC buildings with other transmission substation upgrade projects. In the reporting period 2019- 2020, PG&E completed four new installs for a total of 120 MPAC buildings since 2005. PG&E estimates this avoided $2.6 million in capital expenditures over traditional upgrade methods for an aggregate $72.4 million avoided capital costs.

- PG&E's Community Wildfire Safety Program took preparatory steps to reduce the impacts of wildfires on communities per CPUC orders with grid modernization projects that: (1) ameliorated data and notification portals, (2) improved and refined risk and impact modeling, (3) gathered higher resolution data inputs from weather stations and cameras, (4) deployed drones to inspect assets for analysis using AI (Sherlock & Waldo), (5) harden the grid against ignitions per their wildfire mitigation plan, and (6) enhanced outage management projects (OMT and ILIS).
- PG&E's Building Benchmarking Portal (BBP) provides aggregate, whole-building energy usage data to requesting building owners, so they can benchmark energy usage online. In 2020, BBP received over 6,000 requests for whole-building energy data; it is likely these commercial and multi-family building owners requested this data to fulfill the CEC Building Energy Benchmarking Program and select local government benchmarking reporting requirements. Including BPP, PG&E further developed, improved, and/or maintained customer empowerment tools, such as ED&M, Share My Data, Stream My Data, TOU rates, usage data sharing with academic institutions and others, thanks to their advanced meters.
- PG&E reached close to 99% Distribution Substation SCADA installation on its circuits, providing its grid operators with nearly 100% visibility and control over its distribution substations.

Featured Projects

- **Operational Data Network (ODN) Security Program** – PG&E is designing, building, and implementing new security capabilities to upgrade the cybersecurity of its operational data network. These cybersecurity measures for the operational data network include: (1) high-availability, next-generation firewalls for each electric transmission control center, (2) critical transmission substations, (3) identity and access management system (IAMS) program infrastructure, (4) operational security monitoring tools, (5) vulnerability management systems, (6) endpoint protection, (7) incident response and forensic tooling, (8) new threat monitoring and collection infrastructure, and (9) enhanced, secured remote engineering access control systems. These ODN cybersecurity measures go hand in hand with the ADMS upgrade, integrated grid platform (IGP) security, and IAMS projects in progress.
- **Automated Distribution Management System (ADMS)** – ADMS is a software platform for utilities to monitor and control their distribution system efficiently and reliably. PG&E's ADMS SCADA project will integrate three distribution control center applications (D-SCADA, DMS – Distribution Management System, and OMS – Outage Management System) into one platform to monitor, control, forecast, and analyze dynamic grid conditions. In the reporting period, they finished the Analyze/Design phase of the first release ADMS SCADA project. Some software builds started to add functions, such as new fire mitigation functionality. PG&E also began the ADMS network model's Substation Build portion.
- **Demand Response Projects –** Demand response projects aim to change electricity usage by end-use customers from their normal consumption patterns using changes in the price of electricity over time or incentive payments. These price changes and payments are designed to induce lower electricity use at times of high wholesale market prices or when system reliability may be jeopardized. PG&E took several different routes to pilot demand response with

customers of all classes (Residential, Commercial and Industrial <200kW, Commercial and Industrial ≥ 200kW, and Agricultural). A modern grid enables these projects:

Supply Side II DR Pilot (SSP II)

PG&E's Supply Side II DR Pilot (SSP II) enables BTM DERs to participate in the wholesale energy market as Proxy Demand Resources (PDR). The pilot is open to residential aggregators. However, commercial customers and commercial aggregators comprise the portfolio of participants. The 2017 pilot explored whether these types of DERs could respond to wholesale and distribution instructions with no negative impact to grid safety and reliability. The pilot ended without reaching conclusive findings. In April 2020, PG&E AL 5799-E proposed to close SSP II by December 31, 2020.

Excess Supply DR Pilot (XSP)

PG&E's Excess Supply DR Pilot incentivizes customers to shift energy usage to consume more energy at certain times – when there is excess supply on the transmission and/or distribution systems as well as when there are negative wholesale energy prices – as a way to mitigate the net load profiles that substantially vary over the course of a year. The pilot studies whether customers can actively align time of demand with time of supply, and assist with renewables integration in a bi-directional way (DR bid load increases or decreases). In five years of operation outside of energy markets, the pilot had 27 non-residential customers fully enrolled with 16 enrollees coming from the EV Charge Network Pilot Program in order to fulfill their load management plan requirement. These participants are multi-unit residential, small commercial, larger commercial customers, and third-party commercial aggregators. In April 2020, PG&E AL 5799-E proposed to also close XSP by December 31, 2020.

AC Cycling

PG&E's AC Cycling Program gives the utility near real time visibility into an individual premise, the on-premise air conditioner's actual response to a load control event signal to drop energy usage, and the ability to account for any energy usage drop. Beginning in 2017, PG&E installed 2-way direct load control devices (switches) on or near central air conditioners via its SmartAC program. The load control devices integrate auxiliary communication modules with PG&E's DR management system to provide a dashboard of dispatchability and enrollment; this DR management system facilitates CAISO market integration and eventual dispatch. There are 92,000 active participants and the program is not recruiting any new customers. PG&E deployed 15,000 2-way load control switches and replaced 1-way devices only when they malfunction.

AutoDR Program

PG&E's AutoDR uses communication protocol Open AutoDR to automatically reduce a specific amount of energy bid into the market as reducing energy use is the cheapest and cleanest way of procuring energy. With 14 fewer DR events and 0.43 hours less than last year, PG&E called 5 CBP events with AutoDR customers. Event duration dropped to 1.2 hours with average load shed commitments at 79kW, which led to a smaller kWh benefit from AutoDR this year. When customers participate in either PG&E (e.g. SmartRate, PDP, SSP II, AC Cycling) or third-party eligible (e.g. DRAM, CBP, and SSP II) AutoDR programs, participants get an incentive or rebate to install equipment (e.g. smart thermostats to complex EMS and agricultural pumps) that has the ability to automatically, rather than manually, reduce customers' energy use when CAISO calls a DR event.

- **Electric Vehicle Charging Infrastructure** – PG&E's EV Charge Network Pilot Program enables the deployment of make-ready infrastructure[81] to support the potential for installing and activating up to 4,500 EV level-2 charging ports located primarily in workplaces and multi-family housing units.
  PG&E received 819 program applications totaling more than 15,000 potential charging ports by the end of the reporting period during this pilot. Since its inception through the close of Q2 2020, 198 sites moved into final design and pre-construction. 119 of those make-ready infrastructure sites deployed as installed and activated live chargers. The 198 sites will have 4,898 charging ports once operational. As of March 31, 2020, PG&E installed 2,192 ports, which PG&E or the site host can own. Construction of all charging ports will be completed in 2021 and become operational soon after. The program is fully subscribed and is not taking any new applications.

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

5. CONCLUSION

The grid modernization policies pursued by the State of California and implemented by the investor-owned utilities continue to generate benefits for California ratepayers. Several demand response programs operate and perform as cost-effective energy resources. Intermittent, renewable energy generation produces tens of thousands of gigawatt-hours (GWh) of California's daily electricity use at competitive prices. Energy storage resources interconnect and contribute to distribution and transmission grid reliability and support integration of clean renewable resources. Customers have multiple time-of-use rate options that provide price signals to encourage shifting energy consumption to times when energy is less expensive and causes less pollution. Utilities and communities are developing microgrids and other resiliency projects to serve local needs when the larger grid shuts off for safety or emergencies. Based on the utilities' 2020 smart grid annual reports summarized in section 4, IOU grid modernization projects realized nearly $1 billion in benefits in the 2019-2020 Fiscal Year. Most of these benefits calculate from the electric reliability metric of avoided outage minutes to customers, which is then converted to a monetary value.

However, California has a way to go to realize the vision of a smart, modern, and clean grid that is prepared to meet California's ambitious energy and climate goals, while also addressing the challenges posed by the increasing risk of cybersecurity attacks and climate change (risks of wildfires and other extreme weather events, related air quality for California's workers and ratepayers, load curve shifts due to spillover diseases, and more). Achieving these goals will require the coordination of the CPUC, the Legislature, the California Energy Commission, the electric IOUs, and private sector innovators to cost-effectively set standards, regulate, and invest in swift further grid automation, grid hardening, cybersecurity, and communication systems in order to accelerate the adoption of distributed energy resources, such as electric vehicles, demand response, and energy storage. By fulfilling the vision of SB 17 (Padilla) and the DER Action Plan, the CPUC moves California towards a sustainable, affordable, reliable, efficient, and resilient grid. With our rich culture of tech innovation, premier education, agile workforce, entrepreneurship, cooperation, and forward-looking regulation, California will continue our leadership role in the nation's grid modernization research, design, development, deployment, and climate change mitigation.

APPENDIX A – 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 advanced meters / Smart Meters at the customer site, communication networks between the customer and utility, and data collection 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) such as rooftop solar PV arrays 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 energy 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 authorization process that allows customers to easily authorize their utility company to share the customer's energy data with third-party demand response providers, which 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.

De-Energization: See Public Safety Power Shutoff.

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

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 four hours at a time during the state's late afternoon and evening peaks, over the course of a month.

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 (IFOM).

Distribution Deferral Opportunity Report: (DDOR) a report that, along with the grid needs assessment (GNA), provides a characterization of circuits according to cost-effectiveness, forecast certainty, and market assessment to help prioritize projects on the candidate deferral shortlist. The annual DDOR filing also includes a proposed work plan and agenda for the Distribution Planning Advisory Group (DPAG), which DPAG-participating CPUC technical staff, an independent professional engineer providing technical consultation, non-market participants, DER market participants, and IOUs may comment on prior to finalization.

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 as "non-wires alternatives" (NWA).

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 consisting of DER market participants, non-market participants, IOUs, CPUC technical staff, and an independent professional engineer providing technical consultation, who together 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 was required to develop to propose contracts, tariffs, or other distributed 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 distributed energy resources into distribution planning and to modernize their electric grids. The plans also identify the barriers to the deployment of distributed energy resources. DRP also refers to the namesake CPUC proceeding that developed the DRPs.

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 in the Institute of the Environment and Sustainability. The Energy Atlas is the largest set of disaggregated energy data in the nation, and it 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 decisionmakers 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 one- to two-hours in duration can be reduced to less than five minutes.

General Rate Case: (GRC) is a proceeding used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. GRCs also ensure investor-owned utilities (IOUs or utilities) get their rate of returns in compliance with *Bluefield* and *Hope*. For California's three large IOUs, 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 four years as of the 2020 general rate case plan decision D.20-01-002.

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

Grid Needs Assessment: (GNA) an assessment of the distribution grid that identifies grid needs at the substation level and/or feeder level. Forecast needs, or deficiencies, are associated with as many as four distribution services that DERs can provide: distribution capacity, voltage support, reliability (back-tie) and resiliency.

High Fire Threat District: refers to the high fire threat regions in the CPUC's Fire-Threat Map which was adopted by the CPUC in Decision D.17-12-024. The map consists of three fire-threat tiers (Zone 1, Tier 2, and Tier 3) that have increasing levels of risk of wildfires associated with overhead utility power lines and facilities that also support communication facilities.

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 response to variable energy price signals. Utilities can leverage HANs to manage customer load during peak hours and reduce greenhouse gas emissions from peak-priced 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 CPUC'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. IDER also refers to the IDER proceeding, which focuses on developing sourcing mechanisms for the procurement of DERs that advance distribution planning objectives.

Integrated Resource Plan: (IRP) is a comprehensive utility procurement plan 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, and cost while meeting the State's environmental goals in 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 with electricity from the bulk power system.

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) 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. 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.

Order Instituting Rulemaking: (OIR) an investigatory proceeding opened by the CPUC to consider the creation or revision of rules, general orders, 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 or Peak: refers to the hours of the day during 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) is 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 driving the wheels. With 100% clean energy sources, a PEV can become a ZEV.

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

Public Safety Power Shutoff: (PSPS) is a wildfire mitigation measure where a utility pre-emptively turns off electricity to specific geographic areas when gusty winds, dry conditions, and heightened fire risks are forecasted. PSPS events are also referred to as de-energization events.

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 quality demanded by customers while minimizing service interruptions. Reliability is measured using numerous metrics including the number of outages, frequency of outages, and outage duration. Common reliability metrics are:

System Average Interruption Duration Index (SAIDI) is the system-wide total number of minutes per year of sustained outage per customer served in the reporting year.

Customer Average Interruption Duration Index (CAIDI) – is the total customer interruption duration divided by the total number of customers interrupted. CAIDI represents the average time required to restore service to affected customers.

System Average Interruption Frequency Index (SAIFI) is how often the system-wide average customer was interrupted in the reporting year.

Momentary Average Interruption Frequency Index (MAIFI) is the number of momentary outages per customer system-wide per year.

Request for Offer: (RFO) an open and competitive solicitation process whereby an organization requests the submission of offers in response to a scope of work or services 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, 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 reconfigure the distribution network to minimize the customer impact of 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 various matters 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 provide grid support during excursions from normal system conditions of operational voltage and frequency. Smart inverters also provide safety features, and communications capabilities. See Inverter.

Smart Meter: (also known as an advanced 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) 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 known as Vehicle-to-Grid Integration, V2G, or VGI) a framework for utilizing the flexible charging and discharging capabilities of plug-in electric vehicles 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 to protect customer devices.

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.