California Smart Grid

Annual Report to the Governor and the Legislature

in Compliance with Public Utilities Code § 913.2

February 2018

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1. Executive Summary

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

Highlights of the 2017 CPUC Smart Grid-related activities include:

- CPUC Distributed Energy Resources (DER)[3] Action Plan[4] – The Commission continues to implement its vision to support California's DER future in order to facilitate proactive, coordinated, and forward-thinking development of DER-related policy. The Commission's Energy Division formed a steering committee and developed a coordination framework for implementing the vision and goals of the DER Action Plan across multiple proceedings. The Commission is on track to complete action elements in each of three tracks: Rates and Tariffs; Distribution Planning, Infrastructure, Interconnection and Procurement; and Wholesale DER Market Integration and Interconnection.
- Distribution Resources Plan (DRP) – The Commission held several workshops and issued proposals on improving DER Growth Scenarios, developing a Grid Modernization Investment Framework that would provide guidance and a Distribution Investment Deferral Framework that would implement an annual process for utilities and stakeholders. The Commission adopted use cases, methodologies, and initial implementation deadlines for the two primary analyses that indicate optimal locations for DER deployment: the Integration Capacity Analysis (ICA) and Locational Net Benefits Analysis (LNBA).
- Integrated Distributed Energy Resources (IDER) – The Commission passed Resolution E-4889 approving the Utilities' request to procure DERs that would displace or defer the need for capital

[1] The three largest California IOUs are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).
[2] "…the commission shall report to the Governor and the Legislature on the commission's recommendations for a Smart Grid, the plans and deployment of Smart Grid technologies by the state's electrical corporations, and the costs and benefits to ratepayers." (Pub. Util. Code § 913.2)
[3] DERs are defined in Pub. Util. Code § 769 as renewable distributed generation, energy storage, demand response, energy efficiency, and electric vehicles.
[4] The DER Action Plan is available at the Energy Division's Energy Reports and Whitepapers page: http://www.cpuc.ca.gov/energy_reports/.

expenditures on traditional distribution infrastructure. The Resolution directs the Utilities to start their DER solicitations in early 2018.

- Interconnection Reform – The Commission adopted a resolution in May 2017 that ordered the IOUs to revise their Electric Rule 21 Tariffs to implement their five-year Cost Envelope Pilot Programs, which provide greater interconnection cost certainty for developers. The Commission opened a new Order Instituting Rulemaking (OIR) to further streamline Electric Tariff Rule 21 (Rule 21) by leveraging the ICA tool from the DRP.
- Smart Inverters – The Commission approved revisions to Rule 21 incorporating the smart inverter Phase 2 communications standards. Phase 1 autonomous functions became mandatory September 9, 2017, and at the end of 2017 the Commission issued a draft resolution proposing Phase 3 Advanced Functions to be voted on early 2018.
- Energy Storage – The Commission adopted a Decision integrating Assembly Bill (AB) 2868 (Gatto, Chapter 681, Statutes of 2016) into the storage targets in Assembly Bill 2514 (Skinner, Chapter 469, Statues of 2010). That Decision also established a working group process for consideration of a community storage use case. A Decision adopting a framework for multiple use-case storage applications (MUA) was adopted by the Commission on January 11, 2018.
- Plug-In Electric Vehicle Integration – As part of the CPUC's implementation of Senate Bill (SB) 350 (De Leon, Chapter 547, Statutes of 2015), the CPUC received 32 separate proposals from the Utilities for projects and investments to accelerate widespread transportation electrification, improve air quality, and reduce greenhouse gas emissions. These proposals include charging infrastructure deployment, new electric vehicle (EV) rates, rebates and incentives, outreach and education, data collection, and load management efforts. On January 11, 2018, the CPUC approved 15 of the large IOU's priority review pilots for an amount not to exceed $42.8 million. Decisions on the remaining proposals for both the large and small IOUs are expected in early and mid-2018, respectively.
- Demand Response (DR) – The Commission adopted a Decision[5] to provide customers an open and fair market to choose DR providers and provide a level playing field for third parties competing with the IOUs. Additionally, this Decision sets a five-year portfolio cycle and prohibits the use of several types of backup generation as a means of providing DR beginning in 2018.

[5] (D.) 16-09-056, adopted on January 11, 2018.

This report will detail the following:

- CPUC Smart Grid-related activities in 2017 (Section 2);
- IOU Smart Grid project reports and overall ratepayer costs and benefits. (Section 3); and
- CPUC Smart Grid activities that are expected in 2018 (Section 3.2.).

2. Introduction

2.1. What is the Smart Grid?

The Smart Grid,[6] as defined in the State of California by Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009), is a fundamental change in the existing electricity infrastructure that utilizes advances in technology to create a safer, greener, more efficient, and more reliable electricity supply. The objectives in California, per SB 17 and Pub. Util. Code § 8360, are to promote:

- Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid;
- Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security;
- Deployment and integration of cost-effective distributed resources and generation including renewable resources;
- Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources;
- Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation;

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

- Integration of cost-effective smart appliances and consumer devices;
- Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in-electric and hybrid-electric vehicles, and thermal-storage air conditioning;
- Development of functions that provide consumers with timely information and control options;
- Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; and
- Identification and lowering of unreasonable or unnecessary barriers to adoption of Smart Grid technologies, practices, and services.

2.2. California's Evolution to Grid Modernization

The CPUC has been working with the California IOUs and the Legislature on numerous fronts throughout 2017 to advance grid modernization. The resulting initiatives are oriented towards making the grid in California smarter, safer, and better able to accommodate higher penetrations of DERs, while reducing carbon emissions and improving reliability and resiliency. Recent Grid Modernization efforts have built upon smart meter deployment, cost reductions in digital control and communications technology, power electronics, and advanced automation technologies that improve customer reliability and grid resilience.[7] The accelerating adoption of customer-side intermittent renewable generation, primarily solar photovoltaic (PV) systems, has produced new operational challenges and opportunities for the grid, which is driving the current need for IOU investment in Smart Grid technologies. Modernizing grid infrastructure, such that it serves as a beneficial platform rather than an impediment for customer adoption of distributed energy resources, is becoming a priority for the CPUC and the IOUs so that DERs can be interconnected to the grid in a "plug and play" manner.[8]

A planned approach to increase Smart Grid investments is required to increase grid reliability and to reduce safety risk in light of increasing customer adoption of DERs. The Distribution Resources Plan proceeding currently underway will guide new Smart Grid investment requests in future general rate cases

[7] Reliability is measured in number of outages and outage duration. IEEE Standard 1366 defines the following reliability metrics: Customer Average Interruption Duration Index (CAIDI), System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI).
[8] Creating a distribution grid that is "plug-and-play" involves dramatically streamlining and simplifying the processes for interconnecting to the distribution grid to create a system where high penetrations of DER can be integrated seamlessly.

(GRCs)[9] to meet these safety and reliability challenges.[10] The DRPs require the IOUs to begin planning and investing in the distribution system in a way that will enable higher levels of DER adoption than traditional grid planning processes have previously allowed. DERs have the potential to improve reliability and resiliency, particularly for essential emergency-response and disaster-recovery services if DERs are properly planned for and deployed.

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

2.2.1. Deployment Plan Background

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

Through succeeding Decisions, the Proceeding ordered the Utilities to:

- Deploy smart meters and provide customers with smart meter-collected usage data;
- File Smart Grid Deployment Plans and to set the requirements for what the plans must address;
- Protect the privacy and security of customer data generated by smart meters;
- Provide Home Area Networks (HAN) capability on the smart meters;
- Offer downloadable usage data to customers and authorized third parties, referred to as Customer Data Access (CDA);
- Adopt metrics to measure the effectiveness of smart grid investments; and

[9] General Rate Cases are regulatory proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes for a given IOU.
[10] Pursuant to P.U. Code § 769, CPUC Rulemaking (R.) 14-08-013 is considering the IOUs' DRPs.

- Convene an Energy Data Access Committee to determine ongoing access policies and issues.

In 2014, the Commission closed the Smart Grid Proceeding, and ordered the IOUs' Smart Grid Deployment Plans to include the following eight elements:[11]

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

The IOUs filed their 2017 Smart Grid Annual Reports in October 2017.[12]

2.2.2. Smart Grid Costs and Benefits

The three IOUs are required to report on Smart Grid program costs and associated benefits. The costs and benefits shown in Table 1 below reflect the reporting period for the IOUs' Smart Grid Annual Reports, which covers fiscal year 2016-2017 (July 1, 2016 through June 30, 2017). Costs are calculated as the sum of all the Smart Grid programs and investments implemented by each IOU. Benefits are calculated as a sum of avoided cost of utility operations, including environmental, customer service, and Transmission & Distribution (T&D) costs, as well as reliability benefits in the fiscal year.[13] Each IOU has a different approach to calculating the Smart Grid costs and benefits. The data presented here is shown as it was reported to the CPUC by the IOUs. This data has not been vetted by the CPUC and we cannot attest to its accuracy.

[11] Decision (D).14-12-004.
[12] The 2017 annual reports, as well prior annual reports, can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.
[13] Benefits may include those accrued from previously completed projects and does not include all of the benefits that may be realized over the lifetime of the projects. Some Smart Grid projects may not have direct benefits yet, but may enable other programs or technologies that will provide benefits in the future.

Table 1 IOU Costs and Benefits for Fiscal Year July 1, 2016 through June 30, 2017

IOU	Smart Grid Costs ($Millions)	Smart Grid Benefits ($Millions)
PG&E	$237.80[14]	$204.60[15]
SDG&E	$169.37	$93.46
SCE	$ 94.06	$689.90[16]

2.2.3. Ongoing Commitment to Improving Safety and Reliability

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

Pursuant to the goals of Assembly Bill 66 (Muratsuchi, Chapter 578, Statutes of 2013) which directed the IOUs to improve electric system reliability through greater accountability and enhanced reporting, the CPUC issued a Decision in January 2016[17] that required reliability reporting on a more local basis by the IOUs. The IOUs were also directed to report 1 percent of their worst-performing circuits and to annually detail their investment plans for mitigating these reliability issues. Several Smart Grid technologies deployed by the Utilities, such as Geographic Information Systems (GIS) and Outage Management Systems (OMS), are expected to be deployed to mitigate reliability concerns and to automate and improve outage detection while improving reporting.

As the result of the CPUC's commitment to making safety an integral consideration in all of its proceedings, the Utilities in 2016-2017 were refining their safety risk assessments in their GRCs. By identifying, prioritizing, and offering mitigations for their top safety and operational risks, the Utilities are providing the Commission with a stronger rationale for considering proposed GRC investments in infrastructure upgrades, improved training, and safer operations. A top risk identified in the GRCs is the

[14] Of this total, $101.6 million of the costs incurred this past reporting year is represented by the cumulative costs of one distribution automation and reliability project, and one transmission automation and reliability project.

[15] PG&E also reports non-monetized benefits of 99 million avoided customer outage minutes as a result of installing Smart Grid technologies.

[16] SCE's sharp increase in Smart Grid benefits resulted from reported reliability benefits that were roughly three times as large as PG&E's and larger by the same magnitude relative to SCE's 2016 report. The increase in SCE's reliability benefits was driven by its high estimation of 645 million avoided customer outage minutes achieved through its distribution automation program. This was combined with updated Value of Service (VOS) estimates, which calculate the cost of outages and assign a value of $2,85 per customer minute, and this resulted in the estimated savings of nearly $615 million.. (SCE Smart Grid Deployment Plan Annual Report, p.8). This method has not been vetted by the Commission and the CPUC cannot attest to its accuracy.

[17] D.16-01-008 in R.14-12-014

physical and cyber security vulnerabilities of utility facilities. Increasingly, mitigation proposals involve new Smart Grid technologies that enhance safety, reliability, and resiliency and to improve monitoring of grid and pipeline operations and distributed energy resources.

The CPUC also focuses on resiliency. Unlike reliability, which is well-defined with specific quantitative metrics (see Footnote 8 on page 4), resiliency is an emerging Smart Grid attribute. Resiliency can be characterized as both the ability of the system to resist failure and to recover from events that cause outages. Improving the ability of the system to restore operations fully from a high stress situation or event is one of the objectives of many Smart Grid initiatives. Grid modernization initiatives generally enable the utility to develop situational awareness that anticipates problems using automated fault location and smart meters. Such information and technologies contribute to maintaining a more resilient grid by reducing the frequency and duration of outages and enabling microgrids to operate in island mode.[18]

3. Commission Activities Related to Smart Grid in 2017

3.1. 2017 Smart Grid Activities

3.1.1 DER Action Plan

The Commission continues to implement its vision to support California's DER future in order to facilitate proactive, coordinated, and forward-thinking development of DER policy across inter-related Commission proceedings. In 2017, the Commission's Energy and Administrative Law Judge Divisions formed a steering committee and developed a management framework to coordinate implementation of the vision and goals of the DER Action Plan across multiple proceedings. Using this framework, the Commission is on schedule to complete action elements in each of three tracks: Rates and Tariffs; Distribution Planning, Infrastructure, Interconnection and Procurement; and Wholesale DER Market Integration and Interconnection. Notable elements completed in 2017 include consideration of time-of-use periods in R.15-12-012 (Action 1.1.a), development of the Distribution Infrastructure Deferral Framework in connection with the Distribution Resource Plan Proceeding (R.14-08-013) (Action 2.1.c),

[18] 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.

and implementation of the Cost Envelope Pilot to provide additional cost certainty in the interconnection process (Action 2.3.a).

3.1.2 Distribution Resources Plans

Pub. Util. Code § 769[19] required the IOUs to file Distribution Resource Plans (DRPs) by July 1, 2015. The IOUs' filed DRP proposals that contained three primary analyses: 1) Integrated Capacity Analysis, which determines available grid capacity for DER interconnection on every circuit in the IOUs' service territories; 2) Locational Net Benefits Analysis, which identifies the optimal locations for the deployment of DERs to maximize distribution and ratepayer benefits; and 3) DER Growth Scenarios, which forecast DER penetration under different market and policy assumptions. The IOUs' analyses are intended to identify high-value locations for DER deployment, as well as to inform requests for distribution system and Grid Modernization investments in the IOUs' GRCs to accommodate increasing penetrations of DERs. The CPUC must approve or modify the IOUs' DRPs in a way that minimizes costs of DER deployment and maximizes overall ratepayer benefits.

The primary goal of the DRPs is to develop new tools, processes, and investment frameworks that enable the IOUs to improve the integration DERs into both grid operations and the annual distribution planning process. This broadly reflects the Smart Grid goals of grid modernization which includes greater customer choice, improved communications systems, and higher levels of automation to accommodate two-way energy flows.[20] Many of the projects and activities envisioned as part of the DRP support a smarter, cleaner grid.

The Commission instituted Rulemaking, R.14-08-013, to consider the IOUs' July 1, 2015 DRP Applications across the following three tracks:

1. **Analytical/Methodological Issues (Quasi-Legislative)**: Track 1 of the DRP is focused on developing the methodologies for two analyses that will identify optimal locations for DER deployment, including:
    a. **Integration Capacity Analysis**: The ICA will determine the available hosting capacity of every circuit in the IOUs' service territories to accommodate additional DERs. ICA results will be published through online maps and downloadable datasets located on the IOUs'

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

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

websites and will likely be updated on a monthly basis. The ICA will help DER developers site projects in grid locations that are unlikely to trigger system upgrades; will be used by the IOUs in the annual distribution planning process to identify proactive upgrades to increase a given area's hosting capacity in light of forecasted DER adoption; and will serve as the basis for a streamlined (and potentially automated) Rule 21 interconnection process.

b. **Locational Net Benefits Analysis**: The LNBA will determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid traditional distribution system investments. The LNBA will be updated as part of the annual distribution planning process. LNBA results that display candidate distribution investment deferral opportunities will be published in online maps, downloadable datasets, and be made a public tool in advance of a process, as described as part of Track 3 below. Additionally, the IOUs will be tasked with reviewing and selecting deferral projects for solicitation. The LNBA will also state the costs and benefits of DER deployment within each Distribution Planning Area (DPA) in their service territories. This information will then inform DER sourcing activities being determined in the Integration of Distributed Energy Resources Proceeding (R.14-10-003) as well as the Integrated Resource Planning effort (R.16-02-007).

The ICA and LNBA methodologies and use cases were adopted in D.17-09-026, and an initial implementation was ordered by July/August 2018.

2. **Demonstration and Deployment Projects (Ratesetting):** Track 2 of the DRP entails five Demonstration and Deployment Projects that aim to prove the IOUs' ability to plan and operate the distribution system and to manage increasingly higher DER penetrations including:

   Demo A: Implement the ICA for a selected Distribution Planning Area. This project was completed and approved by D.17-09-026 in 2017.

   Demo B: Implement the LNBA for a selected DPA. This project was completed and approved by D.17-09-026 in addition to Demo A in 2017.

   Demo C: Source DER(s) to defer a traditional infrastructure investment and provide net benefits. This project is intended to validate the ability of DERs to defer or avoid investments in traditional distribution infrastructure and to achieve net ratepayer benefits as estimated by the LNBA.

   Demo D: Operate the system at high penetrations of DERs. This project calls for the Utilities to integrate high penetrations of DER into their distribution operations, to demonstrate the operations of multiple DER in concert, and to coordinate operations with third parties and customers.

Demo E: Plan and operate a microgrid. This project will demonstrate a microgrid where DERs (both customer- and utility-owned) serve a significant portion of customer load and reliability services. Furthermore, it will demonstrate the use of a DER management system (DERMS), which is a software solution that monitors, controls, and optimizes both third-party- and utility-owned DERs.

3. **Policy Issues**: Track 3 of the DRP addresses a number of policy questions related to incorporating new tools and forecasting methods into existing distribution system planning and investment processes:

Sub-track 1 – DER Growth Scenarios and Distribution Load Forecasting: This sub-track is examining methodological issues for developing circuit-level forecasts of DER adoption and distribution load for purposes of the DRP, as well as process alignment with the CEC's Integrated Energy Policy Report (IEPR), IRP, Long-Term Procurement Planning (LTPP), and the CAISO's Transmission Planning Process (TPP). In August 2017, the Commission adopted assumptions for the 2017–2018 planning cycle and approved preliminary methodologies for disaggregating to the circuit level. A Track 3 Proposed Decision issued in December 2017 also orders future procedural work on how different DER growth scenarios can determine optimal DER portfolios that help meet State climate goals.

Sub-track 2 – Grid Modernization Investment Framework: This sub-track is developing 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 cost to ratepayers for widespread adoption of all grid modernization technologies could outstrip the benefits they provide. Meeting the State's climate goals while mitigating ratepayer impacts will require the Utilities to focus on making the most of investments, to support a cost-effective resource mix, and to limit any unnecessary spending. The Commission needs a decision-making framework that will identify the necessary investments to the distribution grid that will yield net ratepayer benefits while supporting a modern grid that supports high penetrations of DERs and maintains safety and reliability. The Commission staff produced a white paper on Grid Modernization in April 2017 to inform Commission decision-making.

The Commission expects to rule on Grid Modernization in 2018 and to establish a process for the IOUs to propose grid modernization investments in their GRCs.

Sub-track 3 – Distribution Investment Deferral Framework: This sub-track is developing a planning framework for identifying, evaluating, and selecting opportunities for DERs to defer or avoid traditional distribution investments and to produce net ratepayer benefits. Process alignment between the distribution planning process, the capital planning process, and the GRC process will be considered in the Deferral Framework. In June 2017, Commission Staff produced a white paper proposing an annual process in which the Utilities seek DER-based options to defer traditional distribution investments for their annual distribution resources planning processes.[21] As of January 2018, this approach is pending before the Commission in the same Proposed Decision that addresses Substation-track 1.

3.1.3 Integrated Distributed Energy Resources

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

In December 2016, the Commission issued Decision (D.) 16-12-036 addressing the Competitive Solicitation Framework and Regulatory Incentive Pilot. It adopted a technology neutral competitive solicitation framework for DERs that can be deployed to defer traditional distribution infrastructure build outs and established a regulatory process to oversee these solicitations. D.16-12-036 authorized a pilot to test a regulatory incentive mechanism through which a utility can earn a 4 percent pre-tax incentive on annual payments to DERs. It required each utility to select at least one deferral project for the pilot, but allowed the utility to select an additional three projects to test various applications of the incentive mechanism. It also specified steps related to pursuing the incentive pilot, including forming a Distribution Planning Advisory Group (DPAG) to engage stakeholders with reviewing candidate deferral

[21] In the Staff proposal, when the utility completes the basic assessments, it would identify candidate deferral projects for presentation in a Grid Needs Assessment and an LNBA. The Grid Needs Assessment would be published and submitted. Utilities would then launch a Distribution Planning Advisory Group to evaluate candidate deferral opportunities and the planning processes that resulted from the Grid Needs Assessment and LNBA. The advisory group would then recommend final distribution deferral projects, and then the Utilities would request Commission approval to launch solicitations.

opportunities. The DPAG advised and was consulted by the Utilities regarding the process for considering proposed distribution deferral pilot projects, contingency plans, proposed counting method, and valuation components for the Incentive Pilot.

In late 2017, the Commission passed Resolution E-4889 ordering the IOUs to move forward with pilot DER solicitations early in 2018. Following the completion of the solicitation process, the Commission, with the Utilities, will evaluate the solicitation process and reconvene the Competitive Solicitation Framework Working Group to develop a technology neutral solicitation document to be used for DER solicitations in the future.

3.1.4 Interconnection Reform

In 2017, the CPUC oversaw significant improvement to the interconnection processes used by generating facilities seeking to connect to the distribution system, including the development of a Cost Envelope Pilot Framework that provided developers with interconnection cost certainty by capping developers' responsibility for interconnection cost estimates for eligible costs at 25 percent (over or under) of the estimate provided by the utility. Additionally, the Commission oversaw the development of an expedited interconnection process for eligible non-exporting storage facilities.

As part of these improvements, the Commission directed the Utilities to begin offering an Inadvertent Export Option that leverages the presence of advanced inverters on a circuit to support streamlined interconnection technical reviews. In March 2017, the Commission approved revisions to Rule 21 to implement a new Inadvertent Export Option for generating facilities that utilize UL-1741 or UL-1741SA-listed grid support (non-islanding) inverters. Projects selecting this option will be able to bypass certain technical screens during Initial Review and inadvertently export power within specified parameters.

3.1.5 Smart Inverters

Smart inverters improve the safety and reliability of DERs and are one of the foundational building blocks of the Smart Grid. Smart inverters' primary benefit is to increase the capacity of the distribution system to accommodate higher penetrations of DERs. Smart Inverters accomplish this by mitigating some of the grid impacts of intermittent variable resources and enhancing these same DERs' ability to serve as grid assets. They also improve operation of the grid through advanced communications and control. Through the direction of the Commission, the Smart Inverter Working Group (SIWG) has developed advanced inverter functionality standards that will ultimately be incorporated into the Electric Rule 21 tariffs.

As of September 9, 2017, the seven autonomous smart inverter functions of Phase 1, adopted per D.14-12-035 in R.11-09-011, have not only been incorporated into the Rule 21 tariffs but also have become mandatory for all inverter-based DERs interconnecting under Rule 21. The Phase 2 communication requirements were added to Rule 21 as of April 2017, and it is expected that the requirements will become mandatory in 2018 depending on available testing and certification protocols. DERs will be capable of communications, with IEEE 2030.5[22] serving as the default protocol used by IOUs to communicate among individual DERs, facility DER management systems, and via DER aggregators.

The Phase 3 advanced functions represent higher levels of DER dispatch and control which are necessary for leveraging DERs for grid operations and planning in the Smart Grid of the future (as is being contemplated in both the DRP and IDER Proceedings). The addition of these requirements into Rule 21 advances the attainment of the CPUC DER Action Plan goal 2.13 to "fully operationalize advanced (beyond Phase 1) smart inverter functionalities [by 2020] to enhance the integration of DERs into the grid."

3.1.6 Energy Storage

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

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

In response to AB 2514, the Commission established storage procurement targets in 2013 of 1,325 MW to be procured by 2020 and operational by 2024. The Commission is in the process of implementing AB 2868 which allows for the procurement of up to 500 additional MWs of energy storage interconnected to the distribution system, both in front of and behind the utility meter. Energy storage has been procured to meet local capacity requirements and is a focus of distribution planning, deferral, and other services. Thus, energy storage is emerging as a crucial backbone of the Smart Grid. SCE and PG&E also have 2016 storage RFO underway and will file their applications by December 1, 2018, for approval of contracts.

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

Rulemaking (R.) 15-03-011 was opened in March 2015 to refine policies and programs required by previous Decisions that established the Energy Storage Procurement Framework. In this proceeding the Commission adopted an April 2017 Decision that specified an implementation pathway for AB 2868; considered, and denied, new energy storage technologies for eligibility; established rules for station power for energy storage; established a working group process for considering a specific community storage use case; and established an automatic limiter for non-IOU load serving entity storage procurement. Energy Division subsequently approved the IOUs' station power tariffs, which are now in place.

Energy Division and CAISO developed a joint framework of rules to govern multiple use applications for storage, and they held a workshop in June 2017. The multiple use applications will allow energy storage devices to provide multiple grid benefits and realize their full economic potential. Following party comments the two agencies developed a revised proposal which was adopted by the Commission on January 11, 2018.

The CPUC Energy Division hosted three workshops focused on implementation of AB 2868. In these workshops, the IOUs presented their initial draft concepts for incorporating new distributed storage programs and investments into the Utilities' 2018 energy storage procurement and investment plans, which are due to the Commission by March 1, 2018.

3.1.7 Plug-In Electric Vehicle Integration

Beginning with R.08-12-009, the Commission began exploring the potential for plug-in electric vehicles (PEVs) to interact with an increasingly modernized grid.

The CPUC's activities related to PEVs are broadly categorized into four areas:

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

In 2016, the CPUC issued Decisions authorizing SDG&E,[23] SCE,[24] and PG&E[25] to deploy charging infrastructure to support PEVs. In 2017, with total budgets of $197 million, the three IOUs continued or

[23] D.16-01-045
[24] D.16-01-023
[25] D.16-12-065

launched their pilots to install the necessary infrastructure to support up to 12,500 charging stations. The IOUs are installing charging infrastructure in multi-unit dwellings, workplaces, and some public locations. The IOUs are using various load management techniques, including rate design and demand response programs, to ensure the new vehicle load is beneficial and not detrimental to the grid.

PG&E, SCE, SDG&E and Liberty Utilities each continue to offer EV time-of-use energy rates for residential customers that charge their EVs at home. SCE and Liberty have commercial time-of-use rates specifically for commercial EV customers. In 2017, SDG&E launched a dynamic EV rate designed specifically for EV drivers that use the charging infrastructure that was deployed in the pilot described above. In this dynamic rate, prices change in response to expected hourly grid conditions. SDG&E notifies drivers of these changes a day in advance.

The concept known as Vehicle-Grid Integration (VGI) harnesses the storage capabilities of electric vehicles to act as a "grid asset" to provide grid services through the Smart Grid. VGI leverages PEVs to maximize customer, grid, and environmental benefits and could lead to increased PEV adoption. The CPUC's Energy Division oversees the administration of PEV-related research projects that are funded by the Electric Program Investment Charge (EPIC). In 2017, the CPUC launched a public working group that will make a recommendation to the CPUC on actions the CPUC should consider to further support VGI. The CPUC will continue working with the California Air Resources Board, California Energy Commission, California Independent System Operator, and Governor's Office of Business and Economic Development to lead this working group. The CPUC is currently implementing SB 350, which among other things, ordered the CPUC to direct the six electric IOUs to file applications for programs and investments to accelerate widespread transportation electrification. The CPUC is currently considering 32 projects that the Utilities proposed within their applications. These proposals include charging infrastructure deployment, new electric vehicle rates, rebates and incentives, outreach and education, data collection, and load management efforts. The proposals include projects in a variety of sectors, such as seaport and airport equipment, buses, delivery trucks, passenger cars, and other medium- and heavy-duty applications.

On January 11, 2018, the CPUC approved 15 of the large IOU's priority review pilots, for an amount not to exceed $42.8 million. The CPUC expects to issue two additional transportation electrification Decisions pursuant to SB 350 during the first half of 2018: one related to PG&E's, SCE's, and SDG&E's remaining transportation electrification proposals; and the second related to Liberty Utilities', PacifiCorp's, and Bear Valley's proposals to support EV infrastructure, rates, and education.

3.1.8 Demand Response

A March 2017 study by the Lawrence Berkeley National Laboratory (LBNL)[26] forecasts that by 2025, Demand Response can provide 10-20 GWh of a shallow, daily, shift of load at a competitive cost. To put this into context, the average daily electricity consumption across all the IOUs was about 515 GWh for 2016.[27] In the coming years, Demand Response will support the integration of renewable generation onto the grid by shifting load to periods of excess supply and averting expensive renewable curtailment and overbuild.

Demand Response also has the potential to provide value to the grid through a fast-responding ancillary services product, and through peak load shedding in areas – such as the Los Angeles Basin, Ventura and San Diego counties – where traditional generation resources will not be able to meet peak demand because space is not available to provide additional transmission capacity to import their energy, to site new generation, or both.[28]

In D.16-09-056, the Commission maintained the role of the IOUs as both administrators and implementers of traditional peak shedding DR programs by allowing the IOUs to continue to procure DR up to 2017 budget levels through a 2020 mid-course review. The Decision fosters its support of third parties by capping the IOU DR portfolios at 2017 budget levels and requiring the IOUs to procure all additional DR from third parties through the Demand Response Auction Mechanism (DRAM), assuming the DRAM pilots are found to be successful. Pilot DRAM contracts with third parties were expected to deliver 40.5 MW in August 2016 and an additional 124.6 MW in August 2017. A major tenet in D.16-09-056 is to provide customers an open and fair market to choose among DR provider options, to enable competitively-set capacity prices, and for the IOUs to provide a level playing field for third parties competing with them. In a precedent-setting action, the Decision prohibits, beginning in 2018, the use of several types of backup generation as a means of providing demand response.

There were two major developments in 2016 in the implementation of Electric Rule 24 tariff (Rule 24).[29] Rule 24 allows bundled customers to bid their load curtailment directly into the CAISO wholesale

[26] "2025 Demand Response Potential Study"
[27] "Electricity Consumption by Entity," *California Energy Commission,* http://www.ecdms.energy.ca.gov/elecbyutil.aspx.
[28] LBNL modeled these findings using more than 200,000 customer load shapes derived from advanced metering infrastructure data, disaggregated by end use, and clustered by climate zone, customer sector, and other factors. Note that wholesale load shifting and bi-directional ancillary services Demand Response products do not exist at this time.
[29] For SDG&E this is known as Rule 32.

energy markets, without going through the IOUs if customers are large enough, or to aggregate with other customers under a third-party DR provider if they are not large enough. The CPUC is beginning to register third-party DR providers, and there are now 15 registered DR providers. The CPUC also led the creation of a simple paperless process for customers to allow their third-party DR provider necessary access to their energy use data. This "click through'' process may be expanded to other distributed energy resources.

In 2017, the Commission completed the following:

- Addressed steps to implement the Competitive Neutrality Cost Causation Principle, which would allow Community Choice Aggregation or Direct Access electric service providers to create and administer demand response programs on a level playing field with investor-owned Utilities;
- Decided to hold a 2018 auction for 2019 deliveries through the Demand Response Auction Mechanism pilot. This auction was approved in D.17-10-017; and
- Determined a path forward for development of new wholesale load shifting and load consuming models of Demand Response, and means to address remaining issues with the integration of Demand Response into wholesale markets.

3.1.9 Enhanced Reliability Reporting

Enhanced reliability reporting provides an objective standard and information to foster continuous improvement of reliability issues. The R.14-12-014 Proceeding focused on interpreting and implementing requirements in Pub. Util. Code § 2774.1.[30] D.16-01-008 in R.14-12-014 directs the Utilities to use an enhanced reliability reporting template to report reliability data to the Commission on July 15 of each year beginning in 2017.[31] Reliability data is reported at the system level as well as division or district level. The 2016 Decision requires the determination of sustained reliability deficiency in an area to be based on two to three years of consistently poor performances.[32] The three IOUs report 1 percent of their worst-performing circuits, while PacifiCorp, Liberty Utilities, and Bear Valley Electric Service report

[30] The Commission shall require an electrical corporation to include in an annual reliability report, required pursuant to Decision 96-09-045. This information shall indicate areas with both the most frequent and longest outages, using local areas determined by the commission.

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

[32] Exception would be made for system-wide district level data, which will be excluded in a major event day.

their three-, two-, and one-worst performing circuits, respectively and combine their reporting into a single report for the Commission.

The Decision also allows customers to request reliability information about their circuits via utility websites and to receive responses in a timely manner. All Utilities will conduct at least one annual public in-person presentation about the information in their annual electric reliability reports and will make webinar participation available. However, the Utilities would not have to provide specific reporting to monitor service of essential customers. Furthermore, the electric Utilities are developing a joint proposal to consolidate different reliability-reporting requirements from Commission Decisions and General Orders into a single Commission Decision and General Order. The Commission and the IOUs have discussed this consolidation effort, and it is set to begin in 2018.

Enhanced reliability reporting will help the state's grid modernization efforts by increasing transparency into the reporting metrics for reliability standards and by describing the remediation efforts the IOUs are taking to target and address the worst performing circuits. It will ultimately serve as an assessment tool to measure the progress in grid reliability and security improvements as indicated in SB 17 and Pub. Util. Code § 8360.

3.1.10 Customer Data Access, Energy Data Request, and Other Data Activities

The Commission's Smart Grid Proceeding envisioned leveraging and optimizing the benefits of advanced metering infrastructure (AMI) data to inform diverse and expanding offerings in distributed energy management, such as customer solar, energy efficiency, electric vehicles, demand response, time-variant pricing, and energy storage. Numerous utility data access approaches are required to accomplish these goals.

There are challenges associated with the IOUs' rollout of customer data access programs that Commission Staff is working to address. Utility data access is a relatively new area of public policy, and some of the IOUs have been restrictive regarding the data they will release to customers and to customer-authorized third parties. Furthermore, some IOUs have been slow to address information technology (IT) issues that support these online data access platforms. While progress has been made in some areas, the overall data access process has been slow and cumbersome for some users. As a result, a variety of technical "workarounds" have been developed by market participants to gain access to data needed to provide customer services. Several initiatives were underway in 2017 to improve IOU data access platforms in order to meet the needs of ever-evolving customer energy service offerings. This includes an online Customer Information Service Request (CISR) form, automated "click through" customer authentication, expansion of data available for different levels of access, timely availability of data, and a streamlined customer experience to improve transactional efficiencies.

Energy Data Request Process (EDRP)[33]

The Commission established rules and a process that provides access to energy usage and usage-related data while protecting privacy of personal data (D.14-05-016). The Energy Data Request Process (EDRP) is different from customer data access CDA programs, which serve customers or customer-authorized third parties, in that EDRP enables utility data access based on different use cases, each with different levels of aggregation and security considerations. The IOUs maintain on their websites EDRP program information and email addresses for the public to efficiently access information and to request applications.

To request energy data, parties must complete an application that lists the details of their request. The details of requested data are varied, but according to the Decision guidelines, all customer energy use data must be anonymized and aggregated at specified levels according to the needs of each market sector (residential, commercial, agricultural, industrial). Numerous procedural safeguards are in place to ensure customer privacy and to adhere to the best data privacy practices.

Energy Data Access Committee (EDAC)

The data access Decision also established the Energy Data Access Committee (EDAC), a non-adjudicatory body responsible for advising the Commission on data request issues that arise from the EDRP. The EDAC, which meets quarterly, is comprised of representatives from each of the IOUs, the CPUC, the Office of Ratepayer Advocates (ORA), the CEC, local governments, consumer privacy advocates, academic researchers, and rotational interested parties.

One of the biggest concerns put before the EDAC comes from local governments that require utility data to complete GHG inventories under locally-mandated climate action plans. Numerous representatives from city and county planning offices have complained about the quality of the data provided, which show drastic irregularities since the Commission Decision and the new data aggregation rules which went into effect in 2014. Impacts of the Commission's privacy rules on utility data provided to these communities have hampered local climate action plan reporting obligations. These issues were brought to the EDAC's attention at the quarterly meeting in March 2016, and the committee began a

[33] Links to the utility energy data request websites can be found at: http://www.cpuc.ca.gov/General.aspx?id=10151.

study of the problem. The EDAC created a formal subcommittee comprised of EDAC members and relevant stakeholders to develop a recommendation for a GHG Inventory Use Case, with appropriate data specifications, for Commission adoption. The subcommittee expects to have a formal recommendation from the EDAC to the Commission in 2018.

3.1.11 Conversion of Master Metering to Direct Metering

The Commission's efforts to phase out master-metering and sub-metering and replace them with direct utility metering[34] will bring the benefits of smart meters to more customers and raise customer awareness of their electrical usage and costs.

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

Utilities have submitted annual status reports to the Commission for 2015 and 2016 and filed Advice Letters in 2017 to request continuation of the conversion program pursuant to Ordering Paragraph (OP) 13 of D.14-03-021[35]. The Commission issued Resolution E-4878 in September 2017, to authorize all currently participating Utilities to continue their Mobile Home Park Utility Upgrade Pilot Programs until the end of 2019.

3.2. Smart Grid Activities Expected in 2018 at the CPUC

Below is a list of some of the Grid Modernization and Smart Grid development projects anticipated in 2018:

- DER Action Plan – The Commission will continue to support the realization of the vision expressed in the CPUC DER Action Plan. Many of the action items will continue and/or be completed in 2018 as described throughout this report. Notable elements to be completed in 2018 include the study of residential default time-of-use (TOU) rates through pilots (Action 1.11), analytical tools designed to assess the value of DERs that can support the review of a net energy

[34] By default, the replaced meters will be smart meters unless a customer opts out.
[35] D.14-03-021 OP 13: Any utility may file a Tier 2 Advice Letter within 45 days of the second annual status report to request continuation of the conversion program if the actual experience to that point appears to warrant continuation of the program without major modification. Among other things, the advice letter filing should specify the application period and the application process and should include a target for converting an additional number of spaces, either as a whole number or a percentage of the remaining spaces in the utility service territory potentially eligible for conversion.

metering (NEM) Successor tariff (NEM 3.0) (Action 1.12), consideration of the use of the ICA to streamline utility interconnection processes (Action 2.11), and research critical to vehicle-grid integration (VGI) for incorporation into transportation electrification policy (Action 3.7).

- Distribution Resources Plan – The ICA and LNBA methodologies and use cases adopted in D.17-09-026 are expected to be operational in 2018. Decisions in 2018 are expected to cover the following key components of the DRP: Distribution Investment Deferral Framework, Grid Modernization Framework, guidance on Growth Scenarios and forecast disaggregation methods, and DRP planning use cases to inform IDER cost effectiveness, NEM 3.0 and Integrated Resources Planning (IRP). The IOUs will continue implementation of their DRP field demonstration projects.
- Energy Storage – The CPUC's and the California Independent System Operator's (CAISO) proposed rules to govern multiple use-case applications for storage was adopted by the Commission on January 11, 2018. The MUA framework represents an important first step in promoting the ability for energy resources to provide multiple grid benefits and realize their full economic potential and the framework will be implemented in subsequent storage Requests for Offers (RFOs). SCE and PG&E have their 2016 storage RFOs underway with the execution of contracts awaiting Commission approval, which is expected in 2018. All three IOUs will file their 2018 Storage Procurement Applications in March that will include additional program and investment proposals for up to an additional 500 MW of distributed energy storage pursuant to AB 2868.
- Interconnection Rule 21 – Rulemaking 17-07-007 will continue to consider policy and programmatic changes to further streamline the interconnection process. A primary goal of the Rulemaking is to leverage the ICA being developed in the utility Distribution Resource Plans Proceeding (R.14-08-013) to further streamline the Fast Track process in Rule 21. The Commission will also continue implementation of Assembly Bill 2861 (Ting, Chapter 672, Statutes of 2016), which authorizes the CPUC to establish an expedited interconnection dispute resolution process that strives for a binding resolution of interconnection dispute within 60 days.
- Smart Inverters – The adoption of smart inverter Phase 3 advanced functionality into Rule 21 is expected by early 2018. Rulemaking 17-07-007 will consider operational requirements of smart inverters including rules and procedures for adjusting smart inverter functions via communication controls.

- Integrated Distributed Energy Resources (IDER) - In early 2018 the Utilities will start DER solicitations to defer planning upgrades. In the second quarter of 2018, the Commission and the Utilities will evaluate the solicitation process and reconvene the Competitive Solicitation Framework Working Group to develop a technology-neutral solicitation document to be used for DER solicitations.
- Transportation Electrification – In early-mid 2018, the CPUC expects to issue three transportation electrification Decisions pursuant to SB 350: two related to the large IOUs' transportation electrification proposals and the third related to the smaller IOUs' – Liberty Utilities', PacifiCorp's, and Bear Valley's – proposals to support EV infrastructure, rates, and education. Additionally, the CPUC will continue working with the California Air Resources Board (CARB), the California Energy Commission (CEC), CAISO, and Governor's Office of Business and Economic Development to lead a public working group that will make a recommendation to the CPUC on any actions the CPUC should take to further support vehicle-grid integration.
- Demand Response - The Commission will undertake steps to implement the Competitive Neutrality Cost Causation Principle, which would allow Community Choice Aggregation (CCA) or Direct Access (DA) electric service providers to create and administer demand response programs on a level playing field with the IOUs. The CPUC will decide on whether to hold a 2018 auction for 2019 deliveries through the Demand Response Auction Mechanism (DRAM) pilot. Additionally, the CPUC will determine a path forward for development of new wholesale load shifting and load consuming models of DR, and expects to address any remaining issues with the integration of DR into wholesale markets.
- General Rate Cases - The Commission is expected to complete SCE's 2018 GRC (A.16-09-001), which includes a number of large Grid Modernization-related proposed investments.

4 Smart Grid Projects in California

4.1 Summary of IOU Activities in 2017

The State of California and the California IOUs continued to advance Smart Grid development initiated in 2009 pursuant to SB 17. Utility activities are reported in the Smart Grid Annual Reports, which are filed by the IOUs each October, per D.10-06-047[36], and are organized into the categories below:

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

The IOUs are also required to report the monetary value of benefits derived from Smart Grid activities. The methodology for calculating benefits among the three Utilities has some variability and reliability benefits are the biggest category for each IOU. In prior years each Utility estimated their reliability benefits using a Value-of-Service reliability model developed by the Lawrence Berkeley National Laboratory (LBNL). This model is used to determine reliability benefits by monetizing reductions in customer minutes of interruption that are achieved through fault location isolation and service restoration (FLISR) and other technologies.[37] However, for the 2017 report, SCE updated how reliability improvements that are achieved through distribution automation are calculated and valued. SCE did this in order to align its estimates with those in tis 2018 General Rate Case. As a consequence of SCE's new methodology, SCE's calculated benefits are significantly higher than those recorded by

[36] The names of the reports are as follows for SDG&E, SCE and PG&E respectively: "SDG&E Smart Grid Deployment Plan 2017 Annual Report", "Southern California Edison Smart Grid Annual Deployment Plan Update", and "Pacific Gas And Electric Company Smart Grid Annual Report – 2017." All of these reports can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

[37] 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 is able to minimize the number of customers impacted by an outage and isolate the outage to reduce restoration times. With FLISR, outages that may have been a one- to two-hours in duration can be reduced to less than five minutes.

SDG&E and PG&E. The costs and benefits shown in Table 1 were accrued from July 1, 2016 to June 30, 2017, which is the reporting period of the 2017 IOU annual update reports.

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

1.Customer Empowerment

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

2.Transmission and Distribution Automation/Utility Operations

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

3.Cyber and Physical Grid Security

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

4.Integrated and Cross-Cutting Systems

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

5.Asset Management, Safety, and Operational Efficiency

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

4.1.1 Advanced Metering Infrastructure Deployment

Table 2 Advanced Metering Infrastructure (aka Smart Meters) Rollout[38] as of Oct. 2017[39]

IOU	Total Number of Electric Smart Meters (Millions)	Electric Smart Meter Opt-outs (No. of customers)	Percentage of Opt-outs	Customer Complaints (escalated) [40]
PG&E	5.51	50,905	0.92%	10
SDG&E	1.44	2,730	0.26%	0
SCE	5.08	757	0.01%	494
Total	12.03	54,392	0.45%	504

Source: IOU Data Requests

In 2007, with Commission approval, the IOUs began full deployment of Advanced Meter Infrastructure, which was largely completed in 2013. Electric opt-outs refer to customers who have either declined to adopt smart meters or returned to using analog meters. Escalated customer complaints have increased over the past year by 5.66 percent.

[38] These statistics only include data as reported by the State's electric Utilities in the Smart Grid Annual Reports. The State's gas Utilities have also deployed millions of Smart Meters.

[39] The reporting period was from November 1, 2016 to October 31, 2017.

[40] Escalated complaints are customer complaints regarding smart meters that have gone through the complaint process and reached resolution. The number of escalated complaints increased from last year's level by 27, or by 5.66 percent.

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

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

Costs

Table 3 SDG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2016 through June 30, 2017

Task	Value
Customer Empowerment and Engagement	$9,390,000
Distribution Automation and Reliability	$109,371,000
Transmission Automation and Reliability	$4,283,000
Asset Management, Safety and Operational Efficiency	$7,915,000
Security	$32,520,000
Integrated and Cross-Cutting Systems	$5,895,000
Total Estimated Costs	$169,374,000

Benefits

Table 4 SDG&E's Estimated Smart Grid Benefits[41] Realized for Fiscal Year July 1, 2016 through June 30, 2017

Benefit	Value
Economic Benefits	$33,545,000
Reliability Benefits	$34,626,000
Environmental Benefits	$11,400,000
Societal Benefits	$13,888,000
Total Estimated Benefits	$93,458,000

[41] "Economic benefits are primarily the result of reduced and avoided costs of utility operations. Reliability benefits estimate the societal value of avoided outages for customers among residential, commercial, and industrial classes. Environmental benefits estimate a value of avoided greenhouse gas and particulate emissions, while societal benefits include other costs avoided by customers, such as the avoided cost of gasoline for transportation fuel when electric vehicles or helicopters are used as alternatives." (SDG&E Smart Grid Deployment Plan 2017 Annual Report, page 10).

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

- SDG&E saw significant growth in NEM distributed generation (DG) with residential and commercial customers connecting nearly 21,000 new systems (primarily solar), bringing the total number of interconnected distributed generation (DG) systems interconnected to nearly 114,000;
- Customer energy storage deployments grew rapidly in the commercial/industrial sector and additional growth is anticipated among residential customers as more products enter the market and time-of-use rates go into effect;
- There are more than 100 MWs of energy storage connected to SDG&E's local power grid including the world's largest lithium-ion battery facility; and
- Plug-in electric vehicle penetration grew to 25,000 vehicles, which is 4,000 more than the previous year.

4.2.1 SDG&E Example Projects

- **Demand Response Management System (DRMS)** – The DRMS project enables integrated management of SDG&E's entire demand response portfolio. This includes program and device management, forecasting, settlement, and analytics/reporting. The second phase, which will deliver DR post event settlement capabilities for the capacity bid program and business reporting, is underway and deployment began in Q3 of 2017.
- **Borrego Springs Microgrid** – This project seeks to establish a microgrid demonstration at an existing substation to evaluate the effectiveness of integrating multiple DER technologies, feeder automation system technologies, and outage management system (OMS) to improve reliability during outages. The most recent phase of this project enhanced the existing microgrid during the reporting period by increasing operational flexibility and automation in order to respond to a variety of outage scenarios and utilize new technologies for enhanced microgrid capabilities. Among these new technologies are a DERMS software system; refined Real-Time Digital Simulation (RTDS) models, which model the distribution system in real time; a new ultracapacitor (a type of energy storage device); and upgraded batteries to accommodate a five day outage.

- **Advanced Distribution Management System (ADMS)** – The purpose of this project is to implement new functions within the new Outage Management System/Distribution Management System (OMS/DMS) that were to enhance distribution grid management. Phase 2 of the project focused on modeling and integrating DERs into the DMS to improve power flow forecasts, to enhance functionality, and to provide visibility to the distribution operator of the impacts these DERs present to the distribution grid. The third phase was completed in 2017 and it implemented functionalities that provide optimal power flow results and the ability to view feeder load management results for any device on the system. Additionally, Phase 3 improved FLISR configurations for SDG&E and it expanded automatic FLISR functions across the entire eligible SDG&E service territory.

- **Unmanned Aircraft System (UAS)** – The objective of the program is to research and evaluate unmanned aircraft systems use cases such as investigation & research capabilities of preprogramed flight pattern software, data storage, anomaly detection software, and a customer notification system. Following the Federal Aviation Administration's (FAA) easing of the Remote Pilot Certification eligibility requirements, SDG&E created a UAS Training Program. This program allows its employees to become certified and then to use UASs within their daily work as needed. SDG&E has purchased an Infrared (IR) Sensor to be used with radiometer data to improve SDG&E's data collection capabilities and to monitor its infrastructure located in remote areas that are too difficult for ground crews and helicopters to access.

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

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

Costs

Table 5 SCE's Estimated Smart Grid Costs for Fiscal Year July 1, 2016 through June 30, 2017

Task	Value
Customer Empowerment and Engagement	$ 6,705,000
Distribution Automation and Reliability	$ 73,475,000
Transmission Automation and Reliability	$0[42]
Asset Management, Safety and Operational Efficiency	$1,707,000
Security	$0[43]
Integrated and Cross-Cutting Systems	$12,177,000
Total Estimated Costs	$94,064,000

[42] There were no active projects in this category during the reporting period.
[43] The Common Cybersecurity Services (CCS) platform project was completed and deployed during the 2016 update reporting period.

Benefits

Table 6 SCE's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2016 through June 30, 2017

Benefits	Value
Operational Benefits	$60,200,000
Reliability Benefits[44]	$614,800,000
Demand Response/Conservation Benefits[45]	$14,900,000
Total Benefits	$689,900,000

Highlights of SCE's Smart Grid deployment update include:

- Development of rates and programs to encourage energy conservation and peak load reductions with technologies such as EVs and smart thermostats while protecting customer data privacy;
- Continued development of projects that will allow SCE to manage the maintenance and replacement of distribution infrastructure based on the health of the equipment versus a time-based pro-forma approach;
- Continued implementation of distribution automation and reliability projects to improve the Utilities' information and control capabilities of the distribution network;
- Increased procurement and investment in energy storage, including a minimum of nearly 200 MW of distribution level storage for SCE's 2016 and 2018 Energy Storage Procurement Plans; and
- Continued improvements to SCE's Demand Response portfolio processes and systems to create efficiencies with CAISO wholesale market integration.

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

[45] According to SCE, "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."

4.3.1 SCE Example Projects

- **3rd Party Smart Thermostat Program** – SCE is working with some of the leading Internet-connected smart thermostat vendors and system providers to enroll customers in a demand response program that utilizes smart meter interval data. After the two-year study in 2013 and 2014, SCE started the Save Power Day program in June 2015 and has approximately 41,000 participants enrolled as of September 2017. SCE has surpassed its goal of having 35,000 customers enrolled by the end of 2017.

- **Consolidated Mobile Solutions (CMS)** – This project will enable field personnel, system operators, and office workers to share real-time information related to software systems in order to reduce customer outage time, to improve safety, and to enhance SCE's workforce productivity. Deployment of CMS to troublemen, maintenance and inspection crews was completed in mid-2017.

- **Circuit Automation** – SCE began this program in order to automatically or remotely restore power to customers after outages caused by faults and to minimize the impact on customers of outages that occur in the ordinary course of business. During the 2017 reporting period, SCE installed 133 remote control switches and spent $3,860,000.

- **Charge Ready Program** – The Charge Ready Program is an initiative to deploy electric vehicle charging stations at locations where EVs will be parked for four or more hours, such as multi-family dwellings, workplaces, fleet parking, and destination centers. SCE also conducts market education to develop awareness of EVs and their benefits to the grid. As of June 2017, SCE had 72 sites and 1,087 ports committed for overall deployment, and had completed infrastructure in 16 sites and 200 ports.

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

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

Costs

Table 7 PG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2016 through June 30, 2017

Task	Value
Customer Empowerment and Engagement	$34,060,000
Distribution Automation and Reliability[46]	$68,000,000
Transmission Automation and Reliability	$84,400,000
Asset Management, Safety and Operational Efficiency	$8,700,000
Security	$11,540,000
Integrated and Cross-Cutting Systems	$31,100,000
Total Estimated Costs	$237,800,000

Benefits

Table 8 PG&E's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2016 through June 30, 2017

Benefits	Value
Direct Customer Savings	$2,500,000
Avoided Costs	$6,400,000
Customer Reliability Benefit[47]	$195,700,000
Total Cost Savings	$204,600,000
Avoided Outage Minutes[48]	99 million minutes

[46] This figure includes $194 Million for the Distribution SCADA program incurred since program inception. $51.6 Million were incurred during the reporting period.

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

[48] The avoided outage minutes are calculated based on customer interruption minutes that were saved as a result of FLISR technologies. While this metric was not provided in SCE's and SDG&E's Annual Smart Grid Reports as a separate category, both monetize their systems' avoided outage minutes as part of their reliability benefits. Note that PG&E's data represents the number of prevented outage minutes from fault isolation and restoration of power to a significant number of customers during the winter 2017 storm season, which was characterized by numerous outages from extreme storm events across PG&E's service territory. The 2017 figure has not been vetted by the Commission and the CPUC cannot attest to its accuracy.

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

- Continuing evaluation of the value streams of enabling DR resources that are to provide new services to enhance reliability and to support T&D operations;
- Increasing customer awareness and engagement in managing their energy use, such as through providing EV customers with a time-of-use rate schedule to encourage off-peak charging;
- Enhancing access to energy data to qualified academic researchers, local governments, and state and federal agencies in order to promote EE, DR, and GHG reductions, and to advance Smart Grid policy goals as these groups fulfill various research, planning, and statutory obligations;
- Evaluating the feasibility of a large-scale compressed air energy storage (CAES) facility that could be used to manage intermittent renewables and other generation; and
- Improving PG&E's capabilities to effectively anticipate, prevent, and respond to a new and emerging class of cyber and physical threats to the grid.

4.4.1 PG&E Example Projects:

- **Demand Response Plug-In Electric Vehicle (DR PEV) Pilot** – The goal of the DR PEV Pilot is to demonstrate the technical feasibility as well as the value of managed charging of EVs as a flexible and controllable grid resource. By December 2016, the DR PEV Pilot dispatched 209 DR events, totaling 19,500 kWh. The Pilot was deemed a success as 98 percent of the participating customers indicated that they were satisfied with the program.
- **Energy Alerts** – This program offers certain PG&E customer accounts[49] the Bill Forecast Alert, which allows customers to set personalized budget thresholds and notifications for when they are projected to exceed that amount during their monthly billing cycle. By the end of calendar year 2016, participants saved approximately 9.2 gigawatt-hours of energy and 2.7 MW of residential peak demand. This reflects an energy savings increase of 15 percent over 2015's total of 7.8 GWh.

[49] Customers with a single premise, with a SmartMeter™, on their account, and on an supported rate plan (HG1, HE1, HE6, HE7, HE8, HE9, HEA9, HEB9, HEVA, HEVB, HETOUA, HETOUB, G1, E1, E6, E7, E8, E9, EA9, EB9, EVA, EVB) are eligible. The following classes of customers are not supported: DA, Community Choice Aggregation, and Net Energy Metering.

- **Demand Response Transmission and Distribution System Integration** – PG&E evaluated areas where existing and future DR programs can be implemented and designed to support PG&E's T&D planning and operations. Demonstration pilots included the deployment of local DR resources and resource zones that can be called by the Distribution Operator to maintain local system reliability, and to test the feasibility of automated calling of DR resources linked to Supervisory Control and Data Acquisition. The project is complete and the final DR T&D report was submitted in April 2017.
- **Electric Vehicle Infrastructure** – This program is a three-year pilot designed to enable the deployment of make-ready infrastructure to support up to 7,500 EV level-2 charging ports located primarily in workplaces and multi-family housing. PG&E is preparing for program launch in 2018 by working with test sites to demonstrate program deployment, conducting solicitation processes for EV chargers, and designing a website, an application form, and a marketing plan.

5 Conclusion

The Smart Grid policies pursued by the State of California and implemented by the state's Utilities continue to generate benefits for California ratepayers. The programs and projects implemented have realized nearly $988 million in benefits in Fiscal Year 2016-2017. However, as indicated by the DER Action Plan, California still has more to do to realize the vision of a smart and modern grid. This will require the coordination of many efforts related to distributed energy resources including: electric vehicles, distribution resource planning, demand response, storage, retail rates, smart inverters, and interconnection. By fulfilling the vision of the DER Action Plan, we will help move California towards a sustainable, affordable, efficient, and effective grid of the future. With its rich tradition of entrepreneurship, technological innovation, and forward-looking regulation, California will continue to lead the nation in Smart Grid development and deployment.

CPUC Smart Grid Vision

In the past year, the Commission made substantial progress on the path to achieving the state's Smart Grid goals. We adopted new methodologies to more accurately estimate the capacity of the distribution grid to host solar, storage, and other distributed energy resources and to calculate the benefits DERs can provide to the grid. We opened a new proceeding to improve DER interconnection by incorporating the newly-adopted hosting capacity tools to streamline interconnection for more projects. Finally, an initial group of new smart inverter functions became mandatory in September, which will enhance the grid's capacity for DERs, and the Commission adopted communication functionality that will become mandatory in the future.

Going forward, the grid, including the poles, wires, transformers, automated controls and high tech control centers, will be increasingly animated by big data tools, cheap sensors and actuators, and two-way energy and power from distributed energy resources. Together, the components of this increasingly smart and nimble grid are a big piece of the emergent Internet of things. Often overlooked, they are quickly becoming the most critical element of our clean energy future, helping customers to guide their own future and to make more efficient use of our clean and renewable power sources.

- Michael Picker, President, California Public Utilities Commission, December 2017.