PACIFIC GAS AND ELECTRIC COMPANY
SMART GRID ANNUAL REPORT – 2019

SMART GRID TECHNOLOGIES

ORDER INSTITUTING RULEMAKING 08-12-009

CALIFORNIA PUBLIC UTILITIES COMMISSION

Contents

CPUC Reporting Requirements and

Pacific Gas and Electric Company's Smart Grid Deployment Plan and Project Updates

Pursuant to Decision (D.) 10-06-047, Ordering Paragraph (OP) 15 and the Smart Grid Deployment Plan D.13-07-024, OP 4, Pacific Gas and Electric Company (PG&E or the Company or the Utility) provides this Smart Grid Annual Report with the following information included:

a) A summary of PG&E's deployment of Smart Grid technologies during the reporting period (July 2018 through end of June 2019) and its progress on its Smart Grid Deployment Plan[1]. Added focus is given this year to grid wildfire protection and safety-related investments which support the development of the Smart Grid to cope with the accumulating impacts of climate change[2].

b) The costs and benefits of Smart Grid deployment to PG&E's customers during the past year, including a monetary estimate of the health and environmental benefits that may arise from the Smart Grid where possible[3].

c) Current PG&E initiatives for Smart Grid deployments and investments.

d) Updates to PG&E's security risk assessment and privacy threat assessment; and PG&E's compliance with North American Electric Reliability Corporation (NERC) security rules and other security guidelines and standards identified by the National Institute of Standards and Technology (NIST) and adopted by the Federal Energy Regulatory Commission (FERC).

Consistent with PG&E's Smart Grid Deployment Plan, PG&E's Smart Grid Annual Report provides information on the status of its PG&E's Smart Grid investments, including Smart Grid

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1 Unless otherwise specified, PG&E has provided cost and benefits for all projects for the period beginning July 1, 2018 through June 30, 2019.

2 To help meet the climate-driven challenge of increasing wildfires and extreme weather events, PG&E announced a comprehensive CWSP in 2018.

3 For information on project costs and benefits in former years, please reference past Smart Grid Deployment Plan Updates on California Public Utilities Commission's (CPUC or Commission) California Smart Grid website at: www.cpuc.gov/General.aspx?id=4693.

Baseline Projects, Smart Grid-Related Customer programs, and proposed Smart Grid Roadmap Projects[4].

4 PG&E's Smart Grid Deployment Plan, Application (A.) 11-06-029, Chapters 4, 5 and 6.

CHAPTER 1

SMART GRID ANNUAL REPORT

EXECUTIVE SUMMARY

1 Smart Grid Annual Report Executive Summary

Throughout the reporting period of July 2018 to June 2019, PG&E continued to build capabilities to deliver on its vision of modernizing its grid. This vision integrates new energy devices and technologies with the grid and allows greater grid safety, resiliency, and customer enablement. PG&E plays a critical role in delivering an interconnected and integrated grid that will define tomorrow's energy landscape for California.

California has experienced dramatic and rapidly evolving environmental changes[5] in recent years, resulting in record drought, unprecedented tree mortality, record rainfall, record heat waves, and extremely strong wind events. The climate change underlying these changes has altered the operating risks of the electric grid[6]. In the CPUC's 2018 Fire-Threat Map, more than 50 percent of PG&E's territory is now identified as having an elevated or extreme wildfire risk. PG&E will continue to take all efforts necessary to maximize the safety of its electric facilities, including with respect to the risk for catastrophic wildfires. PG&E is providing regular updates on efforts to reduce the wildfire risk via PG&E's Amended Wildfire Safety Plan (WSP)[7] and ongoing regulatory and public communications.

Grid modernization through Smart Grid and technology plays a key role in PG&E's strategies to mitigate risks brought on by the changing climate. PG&E is taking advantage of technological advancements to reduce system risks as part of its development of an integrated grid. Smart Grid and key supporting technologies play a key role in increasing the flexibility of the grid to allow for greater resiliency. To foster this, PG&E is implementing technology demonstration projects and pilot programs to evaluate alternative technologies that may harden and

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5 From 2010 to 2018, according to the U.S. Forest Service, over 147 million trees have died in California. Bark beetle infestations and drought have contributed to this. Moreover, as air temperatures rise, forests and land are drying out, increasing fire risks and creating weather conditions that readily facilitate the rapid expansion of fires.

6 Pacific Gas and Electric Company's Initial Response to OII and Order to Show Cause (I.19-06-015) filed June 27, 2019

7 PG&E's Amended 2019 WSP (R.18-10-007) describes the enhanced, accelerated, and new programs that PG&E is and will continue to implement to prevent wildfires in 2019 and beyond, submitted in February 2019 pursuant to the requirements of SB 901.

modernize the electrical system and improve operational capabilities. This includes a demonstration project on Rapid Earth Fault Current Limiter (REFCL), a technology that is able to move the neutral line to the faulted phase during a fault, significantly reducing the energy available for the fault to reduce the risk of ignition.

An integrated grid provides our customers greater flexibility and choice in how they use and obtain value from their energy supply. PG&E customers are leading the adoption of Distributed Energy Resources (DER) and clean technologies, including solar, storage, and electric vehicles (EV). However, the widespread adoption of DER and clean technologies also introduces new challenges in operating the grid, such as those related to two-way power flow, voltage and power quality issues, as well as supply intermittency. Smart Grid and technology advancements help PG&E to manage and optimize this additional complexity, through advanced grid communication, analysis and control capabilities. This is critical to realizing the requirements set forth in CA's Senate Bill 100 (2018), which increases CA's renewable portfolio standard to 60% by 2030 and requires all the state's electricity to come from carbon-free resources by 2045.[8] Clean technology also has the potential to enhance the resiliency of the grid. For instance, PG&E is exploring the use of remote grid configurations and the technology that support it as an advanced solution for wildfire risk mitigation. This includes testing the use of Microgrid (MG) operations for their potential to reduce customer impact during proactive grid operations deployed for reducing wildfire risk or other natural disaster response scenarios. PG&E is actively engaging in new demonstration and pilot projects to help unlock new value streams provided by DERs.

PG&E's Grid Modernization Vision

PG&E's vision for modernizing its grid through Smart Grid and supporting technologies furthers developments towards a secure, resilient, reliable and affordable platform that strengthens the grid while enabling continued gains for clean-energy technologies. This platform gives our customers maximum flexibility, maximum choice in how they use energy, and ultimately

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8 California Public Utilities Commission, Renewables Portfolio Standards (RPS) Program, https://www.cpuc.ca.gov/rps/.

maximum value.[9] PG&E's Smart Grid and technology upgrades are foundational to achieving its grid modernization vision, which focuses on developing the following capabilities:

1. Seamless integration of critical grid data visualization, analysis, and control systems to optimize grid operational efficiency and stability in Real-Time (RT)
2. Enhanced situational awareness and operational flexibility to mitigate more dynamic and extreme weather events while minimizing disruption to customers
3. Enhanced grid communications and cybersecurity infrastructure necessary to securely accommodate the growth in web-enabled grid-tied devices
4. Reliable integration of geographically dispersed DER generation and storage options to provide customers with clean energy choices and to enable grid configurations designed to provide enhanced resiliency

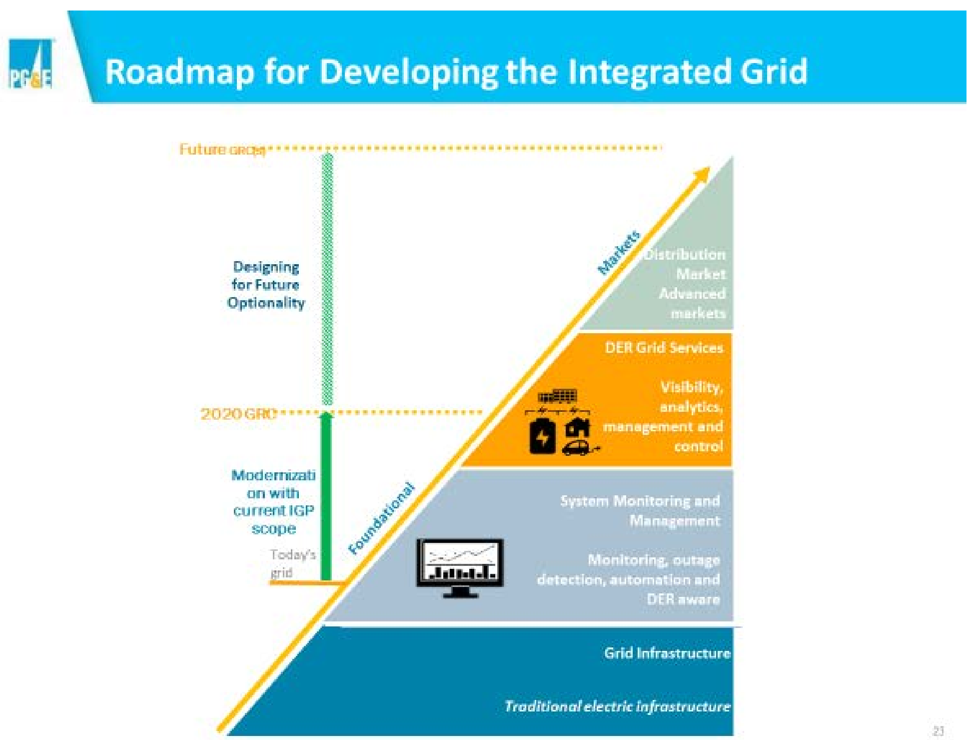

Figure: PG&E's Grid Modernization Plan – Integrated Grid Capabilities

9 Adapted from PG&E's 2020 General Rate Case (GRC) application, Chapter 19, Attachment A: Grid Modernization Plan – 10 Year Vision

PG&E's grid modernization vision is, in part, enabled by the **Electric Program Investment Charge (EPIC)**. Through EPIC, PG&E has been able to cost-effectively develop and demonstrate innovative technologies that advance a broad array of objectives including grid safety, resiliency and reliability as well as customer enablement, and integration of renewable and DERs. EPIC demonstrations aid in identifying key requirements, implementation challenges, and benefit-cost details to inform future deployment. PG&E's EPIC projects also support the creation of new and valuable Intellectual Property (IP), which can lead to improved products and services that help improve the operations of the electricity grid by reducing operating expenses and/or potentially generate alternative forms of incremental revenue that can reduce customer costs.

Given the rapidly evolving energy landscape and the impact of climate change in California, the continuation of technology innovation programs like EPIC is critical to the advancement of grid capabilities to enable advancements on safety, resiliency, and renewable and DER integration. Innovation is further required to enable increased customer choice and empower Disadvantaged Communities. PG&E is excited to embark on new technology demonstrations contained within that plan which build on past projects, meet emerging grid needs and California policy objectives, and ensure that customers and the state can maximize the benefits of this program.

Smart Grid & Technology - Focus Areas

For the July 1, 2018 – June 30, 2019 reporting period, we report on progress made in furthering PG&E's grid modernization vision through Smart Grid and technology investments. Select areas of advancement include:

i. **Wildfire Safety & Grid Resilience**

   a. **Proactive Operational Practices**: PG&E is reducing the wildfire threat through the adoption of proactive operational practices that leverage Smart Grid and technology solutions. Select examples include: (i) refinement and expansion of PG&E's Public Safety Power Shutoff (PSPS) program, and (ii) the development of Resilience Zones to provide important emergency services to PSPS-impacted communities.

b. **Localized situational awareness**: PG&E is implementing enhanced local situational awareness through the development of a complementary set of tools to correctly assess and accurately locate - often in real time - problems occurring on the grid, so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires. Select examples include: (i) setting up of PG&E's Wildfire Safety Operations Center (WSOC), (ii) improved and more localized weather forecasting capabilities, and (iii) satellite-based early warning fire detection.

c. **Asset Inspections, Analytics, & Maintenance:** PG&E is developing new methods to quickly identify issues and enable proactive asset and system maintenance. This in turn reduces the risk of asset failure and potential impacts on our customers. Select examples include: (i) the use of Light Detection and Ranging (LiDAR) to identify vegetation encroachment clearance and hazard tree distances with more precise measurements and to facilitate more efficient ground inspections , (ii) the development of predictive maintenance tools that can identify the onset of equipment failure so that correct action can be taken before actual failure occurs; and (iii) the use of machine learning and data analytics to accelerate accurate inspections to ensure system safety.

ii. **DER Integration & Enablement**: PG&E continues to make significant strides in the deployment of emerging grid technologies (e.g., solar, grid-tied storage and EV charging infrastructure) and the deployment of technologies to facilitate integration and optimization of DER resources. PG&E offers a wide array of incentives to encourage customer adoption of cost-effective energy efficiency (EE) measures, is developing new Smart Grid and technology solutions to encourage the adoption of DERs and is exploring the potential for demand management programs. New and emerging Smart Grid and related technologies that seek to optimize DERs for our customers are being pursued by PG&E through multiple programs, such as technology demonstrations under the EPIC. Examples include (i) the development of an Advanced Distribution Energy Resources Management System (DERMS) and (ii) a demonstration project in collaboration with the

California Energy Commission and Schatz Energy Research Center to develop a multi-customer MG for enhanced reliability and resilience.

iii. **Customer Service**: PG&E provides customers with the tools necessary to understand and manage their energy use and costs through programs such as Home Energy Reports and Stream My Data. PG&E also offers innovative programs that help customers participate in EE. One example is the introduction of financing programs that reduce the up-front cost of large, comprehensive EE projects that would not have been financially feasible otherwise. Another example is the Residential Pay-for-Performance (P4P) pilot which uses the Normalized Meter Energy Consumption (NMEC) approach to estimate customer EE savings directly from AMI-meter readings. PG&E uses market feedback to understand the roadblocks to customer adoption of EE and uses advertising and marketing campaigns to promote engagement with these tools and participation in programs.

iv. Security: The increase in internet-connected Smart Grid and technology devices will be accompanied by a corresponding increase in cyber-security threats. PG&E is collaborating with other California IOUs and national labs to understand the threats that could result from integrating grid communications and controls required for the functioning of the grid. With the installation of PG&E equipment at Idaho National Laboratory (INL), all three IOUs now also have substation instances at the Physical Test Bed, to allow for high-resolution assessments of specific threats. PG&E is in the fifth year of executing the California Energy Systems for the 21st Century (CES-21) program, in partnership with other California IOUs and national labs, to develop the next generation of industrial control systems cybersecurity and automated threat response capabilities.

1.1 Conclusion

PG&E's Smart Grid vision is for a safer, more resilient grid that gives our customers maximum flexibility and maximum choice in how they use energy. Smart Grid and related technologies play a key role in achieving this vision. The energy landscape in PG&E service territory is evolving in complexity – a result of climate induced challenges of heightened wildfire threat and increased DER penetration. Smart grid technologies will have a profound impact on how the grid operates, enabling new operational processes, providing visibility into RT system conditions, and increasing grid operating flexibility. This in turn unlocks new capabilities for proactive grid management and opportunities for continuous improvement. PG&E continues to progress these capabilities through a strategic approach to Smart Grid and technology investments, as highlighted throughout the report.

CHAPTER 2

SELECT SMART GRID AND TECHNOLOGY

FURTHERING GRID MODERNIZATION

2 Select Smart Grid and Technology Furthering Grid Modernization

Chapter 2 details example Smart Grid and technology projects, demonstrations, pilots, and regulatory proceedings taking place over the reporting period that contribute to the achievement of our vision. Project updates are organized under the following categories:

- **Wildfire Safety & Grid Resilience**
- **DER integration & Enablement**
- **Customer Service**
- **Security**

2.1 Wildfire Safety & Grid Resilience

During the July 1, 2018 to June 30, 2019 reporting period, PG&E made substantial progress on several fronts to enhance wildfire safety and grid resilience through the utilization of Smart Grid and technology solutions across a variety of programs, including EPIC and the Community Wildfire Safety Program (CWSP). Technology-dependent focus areas include: (i) proactive operational practices, (ii) localized situational awareness, and (iii) asset inspection, analytics, and maintenance. Additional details on PG&E's work to enhance grid resiliency and wildfire safety are described in its Amended 2019 WSP[10].

2.1.1 Proactive Operational Practices

PG&E is reducing the risk of fire ignition through the adoption of proactive operational practices that leverage Smart Grid and supporting technologies. This includes the expansion of the PSPS program, which proactively de-energizes power lines to prevent wildfires if gusty winds and dry conditions, combined with a heightened fire risk, are forecasted. The program recognizes that wildfire risk cannot be eliminated through vegetation management, system inspection, and system hardening alone. As PG&E expands the PSPS program to higher voltage lines within High Fire Threat District (HFTD) areas, it is developing a risk-based process to assess

[10] PG&E's Amended 2019 WSP, February 14, 2019, R.18-10-007.

the wildfire risk of individual transmission lines, distribution lines and structures to guide PSPS decisions. This will allow PG&E to de-energize specific, targeted lines to reduce wildfire risk and avoid indiscriminate de-energization of transmission & distribution lines.

As part of the PSPS program, PG&E is developing Resilience Zones that will configure areas that can be isolated from the broader grid and energized by mobile generation during PSPS events. Important emergency community services, such as first responders, grocery stores, and gas stations will thereby remain energized while the surrounding areas may be de-energized for safety. This will help alleviate the impact of de-energization on our most vulnerable customers and communities.

Other notable developments furthering proactive operations and maintenance (O&M) include:

- After the CPUC adopted the 2018 Fire-Threat Map, PG&E expanded the Pilot Program in May 2018 by working to install and enable Supervisory Control and Data Acquisition (SCADA) remote control of all reclosing devices on lines serving or running through Tier 2 (“elevated”) and Tier 3 (“extreme”) areas identified in the map (the “Recloser Disabling Program”). Under the Program, protective devices in areas that have a daily fire rating of “Very High,” “Extreme,” or Extreme-Plus” have their reclosing functionality remotely disabled such that they do not automatically reclose after opening due to a fault, therefore reducing the risk of energizing into a fault that could potentially spark a fire. As of June 2019, PG&E completed SCADA-enabling all these targeted Line Reclosers, and approximately 87 percent of the distribution reclosing devices[11] that extend into the Tier 2 and Tier 3 HFTD areas are currently SCADA-enabled. In addition, electric transmission reclosing devices located on nearly 400 transmission lines with voltages of 115 kV or below were included in the expanded 2018 Reclose Disable Program. Over 98 percent of these transmission devices are SCADA-enabled and can have reclosing disabled remotely.
- Enhanced Wires Down Detection: This pilots new methods to detect and locate faulted wires. Using single-phase SmartMeters™, PG&E is testing the ability to send RT alarms to

[11] For more information regarding PG&E’s risk-informed approach, please see PG&E’s 2020 GRC Application at Chapter 2A, and PG&E’s WSP.

the Distribution Management System (DMS) under partial voltage conditions (25-75 percent of nominal voltage). Energized or de-energized wires down create a low voltage condition on transformers that can be used to help detect and locate downed distribution lines more quickly and therefore enable faster response. Faster response may not only reduce the amount of time the line is down but may also allow first responders to more quickly extinguish wire down-related ignitions if they occur.

- EPIC 3.15: Proactive Wires Down Mitigation: Seeks the ability to automatically and rapidly reduce the flow of current and risk of ignition in single phase to ground faults through REFCL. REFCL works by moving the neutral line to the faulted phase during a fault, which significantly reduces the energy available for the fault. This significantly lowers the energy for single line to ground faults by reducing the potential for arc-flash and provides better detection of high impedance faults / wire on ground. If REFCL is successful it will be a major accomplishment in energized wire down safety, potentially stopping a fire from starting in a wire down situation by neutralizing the dangerous aspects of an energized wire down at the moment of failure.

2.1.2 Localized Situational Awareness

PG&E is deploying a powerful set of complementary tools to better assess and more accurately locate, often in near real time, environmental events that pose a danger to the grid so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires. Select examples include:

- WSOC: Bolstered capabilities of PG&E's WSOC which is a physical command center that serves as the central wildfire-related information hub and is staffed 24/7 during wildfire season.
- Granular Weather Forecasting: Developed new techniques for forecasting fire danger as well as new tools to aid in providing RT situational awareness when high fire danger conditions are forecasted. One such example includes a high-resolution weather forecasting model that forecasts important fire weather parameters including wind speed, temperature, relative humidity, and precipitation.

- Weather Stations & Cameras: PG&E installed 200 weather stations and 9 HD cameras in 2018; through June 2019, PG&E installed an additional 249 weather stations and 31 HD cameras to continue to improve its RT knowledge of localized conditions that affect wildfire risk. By 2022, PG&E plans to install a total of 1,300 weather stations (roughly one for every 20 circuit miles in HFTD areas) and 600 HD cameras across its service territory, the latter providing 90 percent visual coverage of HFTD areas and enabling CAL FIRE, Cal OES, and PG&E to quickly confirm, locate and respond to wildfire ignitions.
- Satellite-Based Fire Detection: A state-of-the-art satellite-based fire detection and alerting system has been deployed and is fully operational for the 2019 fire season. The system uses a customized feed of satellite fire detection data to provide new fire alerts on a one-minute refresh-rate in local areas. The system will help PG&E react to new and emerging events quickly. Once the system detects a new fire, PG&E also plans to use the system to initiate fire spread simulations to understand the potential spread of the fire over the next 6 to 24 hours timeframe.

2.1.3 Asset Inspections, Analytics, and Maintenance

PG&E has developed new inspection tools and methods to quickly identify issues and enable proactive asset and system maintenance. This in turn reduces the risk of asset failure and potential impacts on our customers. PG&E is leveraging new technologies, including LiDAR and remote sensing technologies such as drones, to accurately identify risks, including encroachment clearance and vegetation health. Combined with machine learning software, these data are being evaluated to identify dead or dying trees that could pose wildfire hazards or contribute to a wires-down situation.

PG&E is assessing new methods to optimize asset maintenance practices. Unanticipated failure of electric assets due to wear and tear can lead to customer service outages and, in the worst case, fire ignition. The EPIC 3.20, Maintenance Analytics demonstration project aims to reduce unanticipated failures through the development of predictive maintenance capabilities. The project will monitor for signs of failure onset through use of existing data sources such as AMI, PI, Geographic Information System (GIS), and weather. The objective is to develop an analytical model in conjunction with existing PG&E data sets to predictively identify electric distribution equipment issues so that corrective action can be taken before failure occurs.

2.2 DER Integration & Enablement

DERs and clean technology growth continues in PG&E's service territory, with EV sales, solar installations, and grid battery storage adoption rates growing at unprecedented rates. DER milestones achieved in PG&E service territory over the current reporting period include:

- The number of EVs sold in PG&E service territory reached about 235,000 by the end of June this year, a roughly 40% increase over the previous year.
- PG&E's EV Charge Network Program will install up to 7,500 EV level 2 charging ports focused on workplaces and multi-unit dwellings. As of March 31, 2019, 167 sites representing 3,312 ports had signed agreements with PG&E[12]. An additional 329 applications were under review.
- Over 420,000 solar roof-top photovoltaic (PV) systems have been installed by the end of the current SGAR reporting period, an increase of about 14% over the previous reporting period.
  - PG&E has already contracted for greater than 600 MW in utility owned and third-party contracted grid-tied battery storage, in excess of the CPUC mandated goal of 580 MW by 2020.

2.2.1 Managing the Effects of DER on the Distribution System

Balancing loads between three phases on the distribution grid becomes challenging with higher DER penetration. Considerations include the effects of DERs' output, location and characteristics on the distribution grid to mitigate issues such as phase imbalance and voltage regulation problems. PG&E is investing in Smart Grid technologies to establish more sophisticated engineering and operational tools to detect and predict grid issues. One key

12 https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/PGE-EVCN-Quarterly-Report-Q1-2019.pdf.

development includes the testing of an Advanced Distribution Energy Resource Management System through EPIC 3.03. This project seeks to design, procure, and deploy a prototype enterprise DER Management System. This includes development of a cost-effective non-SCADA solution for providing advanced situational awareness and control capabilities. These will enable operators to manage DERs, dispatch DER Registration data requests and monitor Smart Inverter (SI)-based DERs through a head-end platform, and provide an interface to dispatch DERs as a remote grid and Non-Wires Alternative (NWA) solutions.

DERs can provide new products and services for customers, including enhanced resiliency through MG configurations. PG&E is actively assessing and testing MG capabilities and how these may provide greater benefit for our customers. For instance, EPIC 3.11, Multi-use MG**,** seeks to enable a multi-customer MG within the Arcata-Eureka Airport business community and will incorporate four PG&E and Redwood Coast Energy Authority customers. The project will design and develop control specifications and provide SCADA integration to maintain visibility and operational control of the MG in grid-connected and islanded modes and will help satisfy the community's demand for enhanced resilience of their power supply.

The following projects have proven successful in addressing DER integration and enablement and are currently being scaled-up. The multi-year Advanced Distribution Management System (ADMS) deployment is an earlier Phase 2 EPIC demonstration project[13]:

- Multi-year ADMS deployment integrating several mission critical distribution control center applications that are currently spread across multiple platforms. This technology will enable the visibility, control, forecasting and analysis required from a more dynamic grid.
- Transmission and distribution (T&D) SCADA deployments which will achieve close to 100 percent visibility and control of all critical transmission substation and distribution substation breakers over the next few years.

13 For more information, reference EPIC closeout reports: https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/electric-program-investment-charge/closeout-reports.page.

- Expansion of the Fault Location, Isolation and Service Restoration (FLISR) system to approximately 30 percent of PG&E's distribution circuits.
- Continued development of the transmission Energy Management System's (EMS) capabilities, including improved integration of additional synchrophasor PMUs.

2.2.2 Distribution Resources Planning

Distribution Resources Plan (DRP) Overview

Since PG&E's DRP filing in July 2015, PG&E has continually advanced its distribution planning and interconnection processes and tools to more effectively enable customers through the integration of DERs into the distribution grid. Over the last few years, PG&E has worked closely with the CPUC and external non-utility stakeholders on topics such as on DER Integration Capacity Analysis (ICA), process for identifying NWA solutions and grid modernization for DER enablement. Select examples through which PG&E is enabling our customers through the DRP and related items are provided below.

Integration Capacity Analysis (ICA)

ICA, part of California's DRP, is designed to help contractors and developers find potential project sites for DERs. At its core, the ICA is a complex modeling study that uses detailed information about the distribution grid including the physical infrastructure (wires, transformers, voltage regulating devices, substations, etc.), the type and performance of load on the grid (load curves showing maximum and minimum load), and the existing generators and load control measures on the grid. This analysis simulates the ability of individual distribution feeders, or "nodes" on a feeder, to accommodate additional DERs without requiring significant upgrades. On December 31st, 2018, PG&E (and other California IOUs) posted integration capacity analysis (ICA) results for their distribution system on their DRP data portals. In 2019, PG&E is launching a new vendor platform to perform the computationally intensive analysis. Updated system-wide results are anticipated to be published at the end of the year.

Distribution Investment Deferral Process for Identifying NWA Solutions

The Distribution Deferral Opportunity Report (DDOR) and preceding Grid Needs Assessment (GNA) report identified locations on PG&E's distribution grid where NWA solutions may be a feasible and cost-effective solution compared to traditional "wires" solutions. On September 4, 2018, PG&E (and other California IOUs) published its first DDOR, which was mandated in the CPUC's DRP decision related to the distribution investment deferral framework. Shortly after publishing the DDOR, PG&E convened a Distribution Planning Advisory Group (DPAG), an independent planning advisory group that provided advisory input to PG&E on the process it used in developing the DDOR and identifying and prioritizing potential distribution deferral opportunity locations for NWA solutions. On December 1, 2018, after incorporating DPAG input, PG&E submitted an Advice Letter to the CPUC requesting approval to proceed with hosting competitive solicitations for non-wires solutions to address select grid needs through NWAs. PG&E is currently negotiating with counterparties on sourcing NWA solutions as an outcome of the competitive solicitation process. On August 15th of 2019, PG&E will publish its second annual GNA and DDOR reports. While PG&E's initial GNA report only identified substation level capacity level needs, the 2019 GNA and DDOR will include additional distribution grid granularity at the distribution line section level and include additional categories of need beyond capacity, including voltage support, reliability and resiliency.

DRP Data Access Portal

Starting September 1st, 2019, PG&E will roll out an updated DRP Data Access Portal that will include public facing maps for ICA, GNA & DDOR (2019 data). In addition, we will be rolling out ESRI's Application Programming Interface (API) functionality to facilitate the programmatic map data download as well as location file information on our Data Access Portal landing page.

2.3 Customer Service

Over the past year, PG&E has continued to make steady progress providing customers with a robust suite of incentives, services and tools aimed at helping all customers save energy and money[14]. PG&E considers its customers to be the primary driver of its Smart Grid and technology investments. Therefore, without engaged and empowered customers, many of the benefits that Smart Grid and technology systems can offer will be difficult to realize.

PG&E's customer EE programs include established rebate & incentive programs for energy efficient equipment upgrades, whole-building retrofit and upgrade incentive programs (e.g. Advanced Home Upgrade) and customer energy use advisory programs (e.g. Residential Energy Advisor) to help achieve comprehensive and deep building energy reductions[15]. Particularly effective in achieving energy savings has been PG&E's Codes & Standards (C&S) EE program described below. PG&E is also developing newer, innovative programs to help reduce barriers for EE adoption and increase EE cost effectiveness, including:

1. Programs to stimulate customer participation by helping finance the up-front cost of large, comprehensive EE projects that would not have been financially feasible otherwise. 2018 saw market adoption of on-bill financing (OBF) without the need for incentive program participation, affording project developers and customers more flexibility in how they implement their projects. This flexibility allows customers to get measures tailored to their needs and drive the process and timeline themselves. There were more than 70 loans initiated using this new process by the year end, with growth expected to continue into 2019.

2. Meter-based savings programs use actual meter energy use to estimate EE savings. In 2018, PG&E launched its first residential NMEC program, the Residential P4P pilot program. P4P employs energy meter data to understand the impacts of customers targeting deeper energy savings. This program aims to achieve PG&E's goals of

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14 PG&E's 2018 Energy Efficiency Annual Report: http://eestats.cpuc.ca.gov/EEGA2010Files/PGE/AnnualReport/PGE.AnnualNarrative.2018.1.pdf.

15 On January 11, 2018, the California Public Utility Commission (Commission or CPUC) issued Decision (D.)18-01-004, which formalized the third-party solicitation process for EE programs and established key milestones in the path to maintaining a predominantly third-party implemented EE portfolio by 2023.

establishing on-going relationships between PG&E and customers. Data analytics are a valuable tool that enables the targeting of customers with high savings potential.

3. PG&E's Marketplace[16] tool enables customers to search for energy efficient appliances available in the market and to understand the operating cost savings of more efficient appliances.

4. The statewide C&S program saves energy on behalf of ratepayers by collaborating with regulatory bodies, such as the California Energy Commission (CEC) and the United States Department of Energy (DOE), to strengthen EE regulations. The Program conducts efforts to increase compliance with existing C&S regulations to ensure that the State realizes the savings from new C&S and supports local governments that include Reach Codes (RC) as a climate strategy. PG&E also conducts planning and coordination with other Investor-Owned Utilities (IOU) statewide to optimize collaboration and RC activities to prepare for future codes. Program advocacy and Compliance Improvement activities extend to virtually all buildings and all appliances sold in California in support of California's ambitious climate and energy goals. In 2018, C&S was responsible for over 50% of PG&E's EE portfolio electric energy savings.

PG&E's EE programs in 2018 resulted in claimed savings of 498.1 kWh and 165.9 MW in reduced demand[17].

2.4 Security

The increase in internet-connected Smart Grid and technology devices will be accompanied by a corresponding increase in cyber-security threats. PG&E is collaborating with other California IOUs and national labs to understand the threats that could result from integrating grid communications and controls required for the functioning of the grid with the goal of developing the next generation cybersecurity and automated threat response capabilities that can be applied to industrial control systems such as the electric grid. Significant progress was

16 https://marketplace.pge.com.

17 CEDARS California Energy Data and Reporting System.

made in the previous year in terms of leveraging modeling & simulation capabilities to understand the potential effects and mitigations of the malware and tactics employed in the December 2016 Ukrainian power system event. With the installation of PG&E equipment at INL, all three IOUs now also have substation instances at the Physical Test Bed, to allow for high-resolution assessments of specific threats. Over the past year, significant progress was also made across the various sub-components of the Automated Response Research Package, including the continued development of Indicator and Remediation Language (IRL) use cases and continued enhancement of vulnerability scoring capabilities.

CHAPTER 3

SUMMARY OF BENEFITS

FOR SELECTED PROJECTS

3 Summary of Benefits for Selected Projects

3.1 Summary of Benefits for Selected Projects

This year, PG&E's Smart Grid benefits continued to grow, adding an estimated $200.3 million of incremental savings from July 2018 through end of June 2019 for select projects (shown below).

Table 3-1: PG&E's Smart Grid Estimated Project Benefits – July 2018 to June 30, 2019[18]

Category	Annual Savings
Direct Customer Savings (Bill Forecast Alerts (BFA), Demand Response)	$372 Thousand
Avoided Costs (Operational, Capital, Environmental[19])	$5.9 Million
Customer Reliability Benefit[20]	$194 million[21]
Total Benefits	**$200.3 million**
Reliability	87.2 million customer minutes avoided[22]

Projects that contribute to PG&E's Smart Grid project benefits include:

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18 For information on project benefits in prior years, reference past Smart Grid Deployment Plan Updates on CPUC's California Smart Grid website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

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

20 Reliability benefits may vary between the California IOUs due to differences between the projects included and calculated time period of accumulated benefits.

21 Customer Reliability Benefit for FLISR since inception is $828.8 million, with 391 million customer minutes avoided.

22 FLISR has enabled the following statistics for Customers Experiencing Sustained Outages (CESO), avoided outage minutes, and Customer Minutes of Interruption (CMI), respectively:

- Avoided Customer Sustained outages over reporting period: 900,921 (CESO)
- Actual recorded outage minutes over reporting period: 250,904,116
- 5-year average recorded outage minutes: 167,242,848 (CMI)
- 5-year average avoided outage minutes: 69,930,480 (CMI)

- PG&E’s SmartMeter Outage Information Improvement ($0.7 million)
- PG&E’s BFAs (formerly: Energy Alerts)[23] ($0.372 million)
- PG&E’s FLISR project ($194 million)
- PG&E’s Modular Protection and Automation Control (MPAC) project ($2.6 million)

3.2 Benefits Descriptions

3.2.1 Direct Customer Savings (Bill Forecast Alerts/Automated Demand Response (ADR))

BFA estimate what a customer’s bill will be (gas and electric) and alerts them when the forecasted amount exceeds their custom-set threshold. Because forecasts are predictions, estimates may differ from the customer’s actual charges for each statement period. PG&E’s current BFA replaced the former Tier Alerts in March 2016 in anticipation of E1 tier collapse and new Time-of-Use (TOU) rates coming on-line. Additionally, gas usage was added to the forecast for a more complete customer experience. Many customers have been receiving alerts (both Tier and then the Bill Forecast Alert) for 7 years. Early savings results from the programs were a result of initial awareness of household costs associated with energy usage and initial meaningful adjustments made to control this. PG&E’s *2018 Program Year SmartMeter Program Enabled Demand Response and Energy Conservation Annual Report* concluded $62,000 in annual customer savings for Bill Forecast Alert participants with 1,603 megawatt-hours (MWh) in energy savings. Dually enrolled High Usage Alert (HUA) and Bill Forecast Alert customers saved $212,000 annually with 5,417 MWh in energy savings. Singly-enrolled HUA customers experienced 2,501 MWh of energy savings and $98,000 of financial benefits. The program continues to serve customers by providing them with a transparent billing alert and helps customers to manage energy cost with consumption patterns.

Automated DR benefits result from load reductions. No direct customer savings are calculated for AutoDR for the 2018/2019 reporting cycle. More information on the benefits calculation for

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[23] This evaluation was conducted in four phases: data collection, ex post impact estimation, documentation and reporting, and regulatory support and consultation. The data analyzed singly- and dually-enrolled HUA and BFA customers, and calculated Energy Savings and Financial benefits (reported in thousands). Benefits for this program target the Residential customer segment.

this project can be found in the 'Automated Demand Response (AutoDR) Program' program box in the *Emerging Customer Side Technology Projects* section of this report.

3.2.2 Avoided Costs (SmartMeter Outage Information Improvement/MPAC)

Avoided cost benefits represent the total avoided costs associated with SmartMeter Outage Information Improvement and MPAC. SmartMeter Outage Information Improvement project delivers reliability and operational benefits through leveraging SmartMeter data to better understand and resolve customer outages. The program reduced an estimated 8,400 "truck rolls," saving over $700,000 over the reporting period. MPAC helps improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities. Over the past year, the MPAC Installation Program has avoided $5.2 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $69.8 million.[24]

3.2.3 Reliability Benefits (FLISR)

Reliability benefits come primarily from PG&E's FLISR project. FLISR limits the impact of outages by quickly opening and closing automated switches. What may have been a one- to two-hour outage can be reduced to less than five minutes. For the purposes of this report, the benefits are estimated using a Value-of-Service reliability model that was developed in-house using the Freeman & Sullivan analysis incorporating various tax law changes[25]. FLISR procedures have been updated to account for fire index disabling, under which select FLISR circuits may be disabled on extreme fire condition days.

3.2.4 Smart Grid's Role in Furthering Environmental Sustainability

California has adopted the strongest greenhouse gas (GHG) reduction targets in North America. SB 32 requires the state to cut GHG emissions to 40 percent below 1990 levels by 2030. SB 350

24 MPAC benefit totals reflect updated calculations for 2019 Smart Grid Annual Report.

25 FLISR reliability benefits are calculated from actual CMI and CESO savings (tracked per every event) that are applied to the Value of Service calculator.

mandates a goal of doubling EE savings by 2030. As California's largest energy provider, PG&E is committed to helping California achieve these goals.

Smart Grid and technology enable numerous environmental benefits. Over 420,000 customers have installed roof top solar and generate their own power in PG&E service territory. 235,000 customers have decided to replace their traditional vehicles with EVs fueled by the Smart Grid. Smart Grid technologies, including sensing technologies, two-way digital communication, controls and automation, all provide foundations for which new DERs can be connected and controlled via the grid. Given the intermittency and flexibility of DERs like solar and EVs, PG&E's ability to communicate with such assets and in some cases, determine whether it generates or uses energy, enables GHG reductions while building a more resilient grid.

For more information on environmental developments at PG&E, please view PG&E's Corporate Sustainability Report at: http://www.pgecorp.com/corp/responsibility-sustainability/corporate-responsibility-sustainability.page.

CHAPTER 4

PG&E'S SMART GRID DEPLOYMENT

PROJECT UPDATES

Introduction

Chapter 4 provides detailed updates on the Smart Grid and technology projects and programs over the reporting period of July 1, 2018 to June 30, 2019.

4 Summary of Benefits for Selected Projects

4.1 Community Wildfire Safety Program – Select Technologies

PG&E continues to make substantial progress toward its CWSP goals. Below are select technology projects enabling new capabilities to help mitigate the risk of wildfires and protect customers and communities.

Public Safety Power Shutoff (PSPS) Risk Modeling	Approximate Cost Over Reporting Period: N/A
Description: Recognizing that wildfire risk cannot be completely eliminated through vegetation management, system inspection, and system hardening, PG&E has developed, and continues to refine, a proactive de-energization program that was initially developed in advance of the 2018 wildfire season and deployed in October 2018. The program has been significantly enhanced for the 2019 wildfire season and has been deployed during the 2019 wildfire season. PG&E implemented its PSPS program in 2018 to proactively de-energize lines that traverse Tier 3 HFTD areas with extreme fire risk. In developing the PSPS program, PG&E performed extensive benchmarking with San Diego Gas & Electric Company (SDG&E) (the domestic utility with the longest history of proactively shutting power off to avoid wildfire events) in a variety of areas, including meteorology, operational processes, emergency response, restoration, communications and customer support. PG&E is focused on maturing this program to most effectively eliminate potential ignitions during extreme weather conditions. In 2019, lines considered for potential PSPS events include all distribution and transmission lines at all voltages (500 kV and below) that traverse Tier 2 or Tier 3 HFTD areas. In comparison, lines considered for potential PSPS events in 2018 included all distribution lines and transmissions lines at 70 kV or below that crossed Tier 3 HFTD areas. This expansion of the PSPS program increases the targeted distribution lines from approximately 7,000 circuit miles to over 25,000 circuit miles, and the targeted transmission lines from approximately 370 circuit miles to approximately 5,500 circuit miles. As PG&E expands the PSPS program to include higher-voltage lines within HFTD areas, PG&E is developing a risk-based process, or Operability Assessments (OA), to assess the wildfire risk of individual transmission lines and structures. Through these OAs, initially applied to transmission lines, PG&E will apply a risk-informed methodology to evaluate the potential risks of the line and impacts from de-energization. This risk-informed methodology will guide PSPS decisions, allowing PG&E to de-energize specific, targeted transmission lines to reduce wildfire risk and avoid indiscriminate de-energization of transmission lines. This will facilitate compliance with federal reliability and operational requirements (e.g., NERC Reliability	

Standards, and California Independent System Operator Corporation Tariff requirements) and limit wide-area grid reliability risk, while still reducing wildfire risk.

Funding Source: Fire Risk Mitigation Memorandum Account (FRMMA) / Wildfire Plan Memorandum Account (WPMA) per PG&E's Amended 2019 WSP

Status: Active

Benefits Description: Proactively de-energizes high fire risk power lines to prevent wildfires during extreme weather conditions.

Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

Resilience Zones	**Approximate Cost Over Reporting Period:** **$2 Million**

Description: PG&E is continually working to analyze our systems, refine our procedures and further assess how we can minimize the impacts of a PSPS. One of the ways we are working to do this is through establishing new "Resilience Zones." A Resilience Zone is a designated area where PG&E can safely provide electricity to central community resources by rapidly isolating it from the wider grid and re-energizing it using temporary mobile generation during a public safety outage. Though each Resilience Zone will vary in scale and scope, the following equipment will be found at each site:

1. Isolation devices used to disconnect the circuit from the wider grid during a public safety outage
2. A pre-installed interconnection hub (PIH) that enables PG&E to rapidly connect temporary generation and energize the isolated circuit (thereby forming an energized "island")

This work may involve system hardening efforts such as targeted undergrounding in order to ensure safe operation during weather events triggering PSPS. Note that while PG&E's objective is to provide power continuity in Resilience Zones to support community normalcy, PG&E is not in a position to guarantee service on behalf of any customer energized within a Resilience Zone.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP, CWSP, MWC 49M

Status: Pilot phase. First site operational in 2019. An additional four Resilience Zones are currently in the design phase.

Benefits Description: Reduce public safety impact and increase community normalcy during PSPS events.

Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

PGE.com Portal Enhancements	Approximate Cost Over Reporting Period: $0.3 Million

Description: Enhancements were made to PG&E's website by creating a web portal to support the PSPS program. The main focus of the work was sharing maps of de-energization areas and creating interstitials to encourage customers to provide notification information.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Active

Benefit Description: Public safety

Benefit Category: PG&E CWSP - Smart Utility

Weather Station Deployment / Hi-Definition Camera Deployment	Approximate Cost Over Reporting Period: $6.4 Million

Description: PG&E is rapidly increasing its situational awareness—its knowledge of local weather and environmental conditions—to obtain real time information on a more granular level. This type of information is critical for both wildfire prevention and PSPS events and is accessible to respective fire response agencies. From 2018 through June 2019, PG&E installed 449 weather stations and 40 HD cameras to continue to improve its RT knowledge of localized conditions that affect wildfire risk. By 2022, PG&E plans to install a total of 1,300 weather stations and 600 HD cameras across its service territory. PG&E will grant fire agencies access to control the cameras, consistent with an approach taken by SDG&E.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Active.

Benefits Description: Provides real time information on temperature, humidity and wind speed that is used for fire modeling and decision-making processes during a possible PSPS event.

Benefit Category: System reliability and operational efficiency. CWSP - Smart Utility.

Wildfire Analysis & Response	Approximate Cost Over Reporting Period: $2M

Description: PG&E plans to deploy advanced fire spread modeling technology that produces hourly fire spread risk scores for circuits in HFTD areas in addition to modeling fire spread for emerging incidents. The technology deployed was chosen after benchmarking sessions with SDG&E. The system is running near a hundred million fire spread simulations daily for all

PG&E overhead lines in and adjacent to HFTD areas. The main purpose of the fire spread modeling is to understand the total risk profile in the PG&E territory as well as the highest risk circuits or zones hour by hour for asset related fires of high consequence. The weather and fuel moisture inputs utilized in each fire simulation will come from PG&E's PG&E Operational Mesoscale Modeling System (POMMS) weather model (see description below). Asset-based fire spread risk scores for areas potentially impacted by PSPS will be used to maintain situational awareness and used as an additional factor in considering PSPS de-energization.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Active

Benefit Description: Enhanced understanding of fire spread risk based on forecast information. Added ability to rapidly simulate new fires for enhanced awareness and potential impacts.

Benefit Category: CWSP – Smart Utility.

POMMS Enhanced Fire-Risk Modelling	**Approximate Cost Over Reporting Period:** **$1M**

Description: The POMMS is a high-resolution weather forecasting model that forecasts important fire weather parameters including wind speed, temperature, relative humidity, and precipitation currently at 3-km spatial and 1-hour temporal resolution. Outputs from the POMMS model are then used in the National Fire Danger Rating System and the Nelson Dead Fuel Moisture (DFM) model to derive key fire danger indicators such as DFM, Burning Index, Energy Release Component and Ignition Component. These components are then scaled to produce fire danger ratings, the Fire Potential Index (FPI), for operational use. The FPI is derived daily for 91 FIAs covering the HFTD areas within the PG&E service territory. PG&E plans to further test and make any identified improvements to the POMMS modeling system in 2019 and beyond using High Performance Computer capabilities in a cloud-compute environment. Planned improvements include altering the model configuration for increased accuracy, increasing the resolution from 3-km to 2-km, and running a stochastic model ensemble consisting of 6 – 8 model members for probabilistic forecasting. In addition, during high risk weather events, an extremely high-resolution window can be run to provide model output at 0.67 km resolution. Running the model at such high resolution is feasible each day but very computationally expensive. In addition to improving the model configuration and resolution, PG&E plans in 2020 to re-run the 30-year climatology with the now model configuration and resolution to ensure translation from the historical dataset to the forecast. Historical datasets of DFM, live fuel moisture, national fire danger rating system outputs will also be derived. Using these datasets (~240 billion data points), PG&E plans to recalibrate its FPI and Outage Producing Wind (OPW) model in 2020.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Active

Upcoming Plans (Subject to Change): Contract from vendors under review.

Benefit Description: Enhanced model accuracy and granularity. Benefits downstream models such as FPI and OPW, which are main inputs for PSPS

Benefit Category: CWSP – Smart Utility

DMS/OMT/ILIS Enhancements	Approximate Cost Over Reporting Period: $9 Thousand

Description: Enhancements to PG&E's DMS and Outage Management Tool (OMT) to manage PSPS events. The main focus is on management of Estimated Time of Restoration (ETOR), providing operational views of outages to support patrol and restoration, and notification of customers for All-Clear, ETORs and final restoration.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: In-Flight

Benefit Description: Public Safety

Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

Enhanced Vegetation Management – Information Technology (IT) Field Tool	Approximate Cost Over Reporting Period: $2.4 Million

Description: The Enhanced Vegetation Management (EVM)* program was implemented by PG&E's Vegetation Management organization as an additional precautionary measure intended to help further reduce wildfire risks by reducing vegetation above and adjacent to overhead primary voltage power lines in the HFTD.

The EVM work includes the following:

1. Meeting state standards for minimum clearances around the power lines
2. Addressing overhanging limbs and branches directly above and around the lines
3. Removing hazardous vegetation such as dead or dying trees that pose a potential risk to the lines
4. Trimming vegetation around lower voltage secondary lines to prevent damage, when needed
5. Evaluating the condition of trees that may need to be addressed if they are tall enough to strike the lines

Vegetative fuels under power lines may also be considered for treatment, the scope for that effort is captured separately as the "Fuel Reduction" program.

To enable this program, mobile-application-based solutions were rapidly developed and deployed using the ESRI ArcGIS Online Software as a Service (SAAS) platform. These solutions expedited the performance of pre-inspection and tree work activities in the field via work management enablement on hand-held smart phones and devices.

*From August 2018 through 12/10/2018 the program was called Accelerated Wildfire Risk Reduction (AWRR). Beginning 12/11/18 the program was renamed to EVM to reflect changes in the program's scope of work.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Mobile applications were developed and deployed in September 2018 and have been maintained and enhanced since that time to meet the requirements of the program. Additionally, end user support of over 1,000 field users is ongoing with major application enhancements planned quarterly to improve functionality and maintain alignment with business processes.

Benefits Description: These solutions expedited the performance of pre-inspection and tree work activities in the field via work management enablement on hand-held smart phones and devices.

Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

Enhanced Asset Inspections – Drone/AI (Sherlock & Waldo)	Approximate Cost Over Reporting Period: $5.33 Million

Description: PG&E developed an enhanced inspection program as part of the CWSP, known as the Wildfire Safety Inspection Program (WSIP). The WSIP implemented enhanced inspections to be completed on an accelerated schedule for PG&E to inspect its electric facilities in Tier 2 and Tier 3 HFTD areas and address any high priority repairs identified before the 2019 fire season. Under WSIP, the accelerated inspections focus on conditions that could lead to potential fire ignitions, identified through a Failure Modes and Effects Analysis (FMEA), and supplement PG&E's baseline inspection and maintenance procedures. Through the FMEA, PG&E has identified single points of failure of electric system components that could lead to fire ignition. The identification of these failure points will aid in the development of inspection methods that can most appropriately identify the condition of such components, which are designed in accordance with CPUC General Orders (GO) 95, 165, and 174 requirements.

Under the program, PG&E has and will continue to perform detailed ground inspections and climbing inspections (for transmission towers) that focus on failure points capable of visual inspection as well as secondary inspections using drones for all transmission assets and for distribution assets that are on or near those transmission towers.

Sherlock is a web application that allows inspectors to view photographs of assets along with associated data. It also allows for quality assurance review of the data coming in from drone pilots to ensure that only corrected data is viewed by inspectors. In addition, new features will allow for inspectors to file correctives within the application.

The correctives feed Waldo, a computer vision API, where computer vision models are trained to identify problems in an automated fashion. Other applications can send/receive data to/from Waldo to train/retrain models, and/or to receive predictions.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: In Development

Benefits Description: PG&E Community Wildfire and Safety Program - Smart Utility, System Reliability and Operational Efficiency.

Benefit Category: Community Wildfire and Safety Program - Smart Utility. System Reliability and Operational Efficiency.

4.2 Customer Engagement and Empowerment Projects

Over the reporting period, PG&E has made steady progress on several projects to provide customers with the tools necessary to manage their energy usage and costs. Continuing to leverage SmartMeter™ capabilities and providing energy use data access to customers is vital to the company's efforts to help customers understand their energy use and manage their energy bills.

Progress continues to be made on pilot programs exploring the use of demand response (DR) as a behind-the-meter DER that can be integrated into the wholesale energy market but can also address local distribution needs. Demand response programs can be used to both mitigate excessive demand and as a way to support the future grid in times of excess generation by storing this energy for later use. Existing technologies such as storage, EVs and smart devices can be used for this purpose. PG&E is undergoing efforts to enhance customer access to EV infrastructure and programs. By supporting adoption of EVs, PG&E can extend efforts to reduce GHG emissions across the state.

PG&E considers its customers to be the primary driver of its Smart Grid and technology investments. Therefore, without an engaged and empowered customer population, many benefits offered by a Smart Grid would be difficult to realize.

4.2.1 Demand Response Projects

Supply Side II DR Pilot (SSP II)	**Approximate Cost Over Reporting Period:** **$0.94 Million**
Description: The Supply Side II DR Pilot (SSP II) continues the work started in previous DR pilots to enable participation of customer behind-the-meter DERs as DR in the wholesale energy market using the Proxy Demand Resource (PDR) wholesale product. In addition, the SSP II in 2017 was expanded to start investigating the ability of wholesale DR to also provide distribution services, specifically investigating how to operationalize the interactions between wholesale market availability and distribution services availability and starting to develop a method for dispatching available DR resources based on distribution operational needs. Funding Source: Funding for this pilot in 2017 was approved by the CPUC in D.16-06-029, and the CPUC subsequently approved 3 additional years of funding (2018-2020) in D.17-12-003.	

Status: Participants have been bidding into the wholesale energy market. Between April 2015 and June 2019, pilot participants have submitted over 14,200 bids and received over 2,100 awards in the wholesale day-ahead energy market. While the pilot is open to residential aggregators, and several have gone through various stages of the enrollment process, to date none have completed the process and all participants are commercial customers or aggregators. In 2017, the SSP II started investigating the operational feasibility of utilizing DR resources that are integrated in the wholesale energy market to also address local distribution needs. As part of this work, the SSP II was used in conjunction with PG&E's EPIC 2.02 (DERMS) project to test if an aggregation of behind-the-meter DERs could respond to both wholesale and distribution instructions with no negative impact to the safety and reliability of the grid. While work with EPIC 2.02 ended in 2018, the SSP II is continuing to investigate this issue.

Benefits Description: The SSP II is a gateway for more DR resources to be integrated into the California Independent System Operator (CAISO) wholesale market. PG&E has structured the pilot as a bridge between the retail and wholesale market as well as an avenue for third-party DR providers to participate in the CAISO wholesale market. This step is vital to have a self-sustaining third-party DR market in California. Learnings from the pilot were integrated into PG&E's proposed enhancements to its Capacity Bidding Program (CBP) included in its 2018-2022 DR Application, and future results from the SSP II, in addition to inputs from the Distributed Resource Plan and Integrated DERs proceedings, may be used to inform a proposal for distribution service offerings in future DR programs.

The SSP II also provides a pathway for new technologies. Technologies behind the customer meter, such as storage, EVs, and or Smart devices, can play a vital role as grid-responsive assets.

DR programs will act as avenues for participants to provide demand reduction based on the needs of the CAISO and distribution systems. Results of the SSP II will help PG&E and the Commission assess the benefits of DR as a gateway to grid benefits and provide an in-depth understanding of the benefits of behind-the-meter technologies.

Benefit Category: Smart Market – PG&E is continuing to evaluate the value streams of enabling DR resources in a changing operations environment and to provide services to facilitate the reliable and cost-effective integration of renewable resources. PG&E is pursuing discovery of the necessary program attributes that T&D system operators will need in the future.

Excess Supply DR Pilot (XSP)	Approximate Cost Over Reporting Period: $0.54 Million

Description: There has been much written about the changing net load curve, where the "net load" is the total system load minus the renewable generation. This change from the conventional mid-day peak, due in large part to the increased penetration of renewables, dramatically impacts the system operational needs. This is often referred to as the "duck curve." Not only have the net load profiles changed in recent years, they fluctuate substantially over the course of a year. This demonstrates the importance of a flexible solution that can be adapted to fit the ever-changing load profiles. These changes in net load, policy, and technology, create challenges to the grid in balancing against the capacity in T&D and require California to evaluate which market constructs and resources can address future grid needs. Examples of policy tools available to solve ramping issues include TOU pricing where retail rates are aligned with wholesale grid conditions, exporting electricity during periods of excess supply, curtailing renewable resources, or incentivizing customers to shift load on-demand when needed by the grid.

PG&E's XSP is investigating ways to incentivize customers to shift energy usage as a possible way to mitigate these challenges. In the XSP, demand responsive loads are being considered as one of the many resources that can support in-state economical and reliability needs of the future grid. The XSP is a departure from other offerings in that it asks participants to shift energy usage to consume more energy at certain times to help mitigate situations of excess supply on the transmission and/or distribution systems as well as in the case of negative wholesale energy prices. By getting customers to shift their energy consumption to align with periods of excess supply, the XSP hopes to demonstrate that customers can actively assist with renewables integration and improve alignment of supply and demand.

<u>Funding Source</u>: The XSP was originally approved by the CPUC as part of the 2015-2016 DR funding bridge D.14-05-025). Funding for this pilot in 2017 was approved by the CPUC in D.16-06-029, and the CPUC subsequently approved 3 additional years of funding (2018-2020) in D.17-12-003.

<u>Status</u>: The XSP was initiated in 2016 and was approved by the CPUC to continue through at least 2020. Currently there are eight non-residential customers fully enrolled with several other participants that have completed part of the enrollment process. To date, larger commercial customers, and 3rd parties aggregating commercial customers, have generally been more interested in participating in the XSP than small commercial and residential customers.

Since there is currently not a mechanism in the wholesale market to register or bid this type of load increase/shift DR resource, the XSP is an out of market pilot but is designed in a manner to potentially enable market integration in the future. In addition, XSP events were dispatched based on administrative decisions to test the overall construct of response to excess supply conditions, not based directly on actual grid conditions. This enabled broader testing of participants by allowing more flexibility in when test events were called without having to wait for actual excess supply market conditions. However, starting in 2018 the XSP began using day-ahead oversupply forecasts from PG&E's Short-Term Electric Supply group as a way of triggering dispatches, and these oversupply forecasts use day-ahead wholesale market prices as an input.

An additional enhancement to the XSP in 2018 was the introduction of bi-directionality where a participant could provide non-overlapping load increase and load decrease bids. However, even if a participant chose to provide bids in both directions, load increase and load decrease dispatches were treated independently, and energy neutrality was not required.

The XSP has been successful in gaining learnings in a number of its key objectives and, in doing so, has directly and indirectly addressed multiple barriers to renewable integration challenges. In addition, these learnings have helped inform ongoing proceedings at the CPUC and CAISO. The XSP is also being looked at and utilized by other groups. For example, site hosts in PG&E's Electric Vehicle Charge Network (EVCN) program can meet the EVCN's load management plan requirement by participating in the XSP. Including EVCN participants in the XSP enables the pilot to incorporate a technology (EVs) and customer classes (smaller commercial and multi-unit residential) that have been absent from the program.

In 2019, the XSP was also recognized by the Peak Load Management Alliance (PLMA) as one of three recipients of its 2019 Program Pacesetter award. More information about the PLMA awards can be found at https://www.peakload.org/awards, and a webinar about the pilot can be viewed at https://www.peakload.org/dialogue--pg-e-excess-supply-dr. The XSP was also featured in an article in Energy Central and can be found at https://www.energycentral.com/c/em/pges-excess-supply-demand-re.

Upcoming Plans (Subject to Change): While much has been learned, there are still unanswered questions around what should trigger an excess supply event, the effects on local distribution planning and operations, and the interaction with other DR programs that provide load reduction. Based on feedback and learnings from the XSP so far, and as part of continuing to gain insights into the previously mentioned issues, the following efforts are being planned for the XSP:

- Continue to refine the event trigger mechanism to trigger events when excess supply situations are likely to occur based on actual market conditions;
- Continue to provide real-world input into ongoing stakeholder efforts at the CPUC and CAISO;
- Evaluate the value of negative market prices to the incentive structure;
- Continue with the implementation of the EVCN participation option;
- Recruit new participants into XSP to robustly test the new XSP feature set delivered in 2018.

Benefits Description: PG&E envisions that the XSP ultimately will be a program offering that will assist during excess supply conditions. The XSP is meant to explore how customers can help mitigate situations of excess supply on the transmission and/or distribution systems as well as in the case of negative wholesale energy prices, by shifting their load consumption to these periods and contribute to the improved alignment of supply and demand. Learnings from the XSP have helped inform ongoing proceedings at the CPUC and CAISO, including the CAISO's Energy Storage and DER stakeholder process and the CPUC's investigation of new models of DR as a part of the Load Shift Working Group.

The XSP also provides a pathway for new technologies. PG&E believes that technologies adopted behind the customers' meters, such as storage, EVs, and smart devices, can play a vital role as grid-responsive assets to help with excess supply situations.

DR programs will act as avenues for participants to provide load shifts that are tied to when there is excess supply on the grid. Results of the XSP will help PG&E, the CPUC, and the CAISO assess the benefits of DR as a gateway to grid needs and benefits and, in addition, provide an in-depth understanding of the benefits of behind-the-meter technologies.

Benefit Category: Smart Market – PG&E is continuing to evaluate the value streams of enabling DR resources in a changing operations environment and to provide services to facilitate the reliable and cost-effective integration of renewable resources through improved alignment of supply and demand. PG&E is pursuing discovery of the necessary program attributes that T&D system operators will need in the future.

AC Cycling	**Approximate Cost Over Reporting Period: $5 Million***

Description: Under its direct installation program, SmartAC™, PG&E has deployed direct load control devices on or near central air conditioners since 2007. Currently, there are 103,390 active participants on the program who either have legacy 1-way paging devices or the new technology which leverages PG&E's investment in the AMI network by communicating through SmartMeters. In order to improve the reliability of this resource, PG&E conducted extensive testing beginning in 2014 and began deployment of the bidirectional (2-way) technology by Energate/Tantalus in 2017. Energate/Tantalus communicates through Smart Meters. This new technology communicates with PG&E's SmartMeters via a Zigbee Smart Energy 1.1b standard protocol module. Residential SmartMeters at PG&E incorporated this auxiliary communication module since initial deployment to promote Home Area Network and Smart Grid automation. PG&E has integrated the 2-way device head-end control system, Itron's (formerly Silver Spring Networks) Home and Business Area Network (HAN) Communication Manager, with its DR management system, Lockheed Martin Energy's SEEload product, to have a single system of dispatch to support CAISO market integration of its SmartAC program in 2018 and provide a graphically based dashboard of enrollment and dispatchable status.

Funding Source: *PG&E's SmartAC program is authorized through 2023 under D.17-12-003 which provides a balancing account mechanism. Includes marketing, administrative, and device costs

Upcoming Plans (Subject to Change): PG&E has currently deployed nearly 13,000 2-way load control switches. Deployment plans do not entail mass replacement of legacy 1-way technology but rather if existing devices are malfunctioning, they will be replaced. The SmartAC program is currently in a mode of recruiting new customers only to back-fill for attrition and has been approved through 2022 at this level which equates to roughly 10-12,000 customers annually. While PG&E has built out meter level RT visibility for enrollment and dispatchability, future enhancements incorporate RT load control device level status visibility.

Benefits Description: Because 2-way switches are associated with healthy SmartMeter devices, the reliability rate of this resource will improve over 1-way paging devices. By installing 2-way direct load control devices, PG&E has near RT visibility into an individual premise and the air conditioner's actual response to a load control event signal. This facilitates early detection of device malfunction in either under- or over-performance circumstances and lost load can be recaptured quicker. Currently, PG&E uses SmartMeter data to determine an estimate of the number of non-performing devices in its maintenance program. With a disconnect alarm on a 2-way switch, unnecessary truck rolls can be avoided to sites.

Benefit Category: Smart Utility – The 2-way technology provides greater visibility into device behavior, which will be used in more accurate forecasting of load reduction during events, increase the load reduction value per customer, and provide efficiencies in program management operations. Further, demand response is a DER and as such can provide load balancing benefits for grid operators.

4.2.2 Electric Vehicle Integration Projects

PG&E continued to make significant progress is in enablement of EV adoption with its EV Charge Network Program. This is the 2nd year of a three-year pilot whose purpose is to increase access to charging for EVs within PG&E service territory by installing up to 7,500 EV level 2 charging ports focused on workplaces and multi-unit dwellings. As of March 31, 2019, 167 sites representing 3,312 ports had signed agreements with PG&E[26]. An additional 329 applications were under review.

26 https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/PGE-EVCN-Quarterly-Report-Q1-2019.pdf.

The EV Charge Program positions PG&E at the nexus of customer service and emerging infrastructure needs. Public charging infrastructure is needed for California to meets its goal of 5 million zero emission vehicles on the road by 2030. PG&E's dedicated end-to-end deployment of infrastructure will help meet the state's goals. Furthermore, a customized customer-facing web portal and tools, marketing collateral, application process, and community partnerships will foster a level of customer service and public EV education formerly absent.

The program will scale to completion in 2020. For further project information, see the EVCN Quarterly Report: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/resources.page.

Electric Vehicle Infrastructure	Approximate Cost Over Reporting Period: $44.36 Million
Description: PG&E's EV Charge Network Program is a three-year pilot which enables the deployment of service connection and supply infrastructure (make-ready infrastructure) to support up to 7,500 EV Level 2 charging ports. The program focuses on serving two key market segments, workplaces and multi-unit dwellings. Charging ports may be owned by either Site Hosts or PG&E, with PG&E able to own charging ports in multi-unit dwellings and workplaces located in disadvantaged communities. PG&E also administers rebates and participation payments for the EV chargers contingent upon the Site Hosts' attributes, physical location, and ownership model selected. The total program cost will not exceed $130 million. Funding Source: This project was funded through the PG&E EV Balancing Account. Status: In 2019, PG&E fully subscribed the program. As of June 30, 2019, PG&E had received 819 applications for the program, totaling more than 14,000 charging ports. At the close of Q2 2019, 201 sites had been approved and moved into final design and pre-construction phases, including 60 sites that have completed construction, installation, and activation of chargers. PG&E has installed 1,176 ports as of June 30, 2019. The program will scale to complete construction in 2020. For further project information, see EVCN Quarterly Reports: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/resources.page. Upcoming Plans (Subject to Change): See program status for details of upcoming plans. Benefits Description: The EV Charge Network Program positions PG&E at the nexus of customer service and emerging infrastructure needs. Public charging infrastructure is needed for California to meets its goal of 5 million zero emission vehicles on the road by 2030. PG&E's dedicated end-to-end deployment of infrastructure will help meet the state's goals. Furthermore, a customized customer-facing web portal and tools, marketing collateral, application process, and community partnerships will foster a level of customer service and public EV education formerly absent. PG&E is also mindful of potential grid benefits that EV charger deployment may drive, such as load shaping through DR communications and the	

establishment of load management guidelines. This charging and pricing data will help inform strategy for rapid EV growth across the state.

Benefit Category: Smart Utility

Electric Vehicle Rates	Approximate Cost Over Reporting Period: $0.1 Million

Description: PG&E's EV rates provide customers with a TOU, non-tiered electric rate schedule that allows drivers to recharge their EVs at a fraction of the cost of gasoline. The rate is structured to offer low-cost, off-peak rates from 12:00AM to 3:00PM allowing customers to access low cost fuelling overnight and during the day. This helps PG&E integrate new EV charging load by shifting demand overnight when there is ample capacity on the utility grid and higher renewable energy during the day. The EV rates also remove the tiered rate structure of PG&E's default residential rates, which can cause EV charging to be as costly as, or more expensive than, gasoline for higher-usage customers. PG&E offers two EV rates to customers: Home Charging EV2-A (and EV-A) allows customers to meter their home usage and EV charging together; EV-B involves installation of a second utility meter to bill only vehicle charging on the EV rate. Since their introduction in 2013, PG&E has enrolled over 58,000 customers on an EV rate, representing 23 percent of the total registered EVs in PG&E's service territory to date.[27]

Funding Source: GRC

Status: On July 1, 2019, PG&E opened the Home Charging EV2-A rate plan, which replaces EVA. The Home Charging rate plan is also available to battery storage customers. The rate modifies the time of use periods and extends the off-peak period to 12:00am – 3:00pm. Effective July 1, 2019, the EV rate enrolment cap of 60,000 customers has been replaced with rate eligibility criteria that limits cumulative usage to 800% of baseline. PG&E continues outreach activities to EV drivers to increase awareness of EV rates and other options for customers to reduce fuel costs. This includes a partnership with the Center for Sustainable Energy, the administrator of the State's Clean Vehicle Rebate Project, to reach new EV drivers. PG&E also supports several EV ride-and-drive events each year to connect with customers interested in transitioning to an EV.

Upcoming Plans (Subject to Change): PG&E has also proposed a rate plan designed for commercial customers that aims to support public charging and medium- and heavy-duty fleet electrification.

Benefits Description: The current off-peak price for electricity on the EV rate $0.15/kWh, equivalent to approximately $1.50/gallon of gasoline. This low off-peak price allows EV drivers to realize significant fuel cost savings compared to gasoline, which is currently trending above $3.70 per gallon in California.[28] Because of the significant savings off-peak,

27 Percentage of registered EVs in PG&E territory is derived from Veloz's quarterly sales report https://www.veloz.org/wp-content/uploads/2019/07/6_june_2019_monthly.pdf. The cumulative number of customers on PG&E's rate, 58.821, is 23 percent of total EV sales in PG&E territory, 246,225.

28 https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMM_EPM0_PTE_SCA_DPG&f=M.

PG&E estimates that 80 percent of EV charging is done during the hours of 12.m. to 3 p.m., when prices are lowest. This will lower overall charging costs for customers as well as costs for PG&E associated with peak energy use.

Benefit Category: Engaged Customer – this program increases customer awareness and engagement in managing their energy use. With one EV accounting for roughly half of the annual consumption of a typical home, shifting charging behaviors away from peak periods can allow PG&E E to avoid upgrades to local distribution infrastructure, as well as costs for expensive peak-hour energy procurement. In addition, the extension of the off-peak period to 3PM is designed to help support the integration of renewable energy, by reducing the morning and evening ramp period and thereby alleviating stress on the grid.

4.2.3 SmartMeter-Enabled Customer Tool Projects

Energy Diagnostics and Management (includes, Home Energy Reports, Business Energy Reports, Your Account Portal)	**Approximate Cost Over Reporting Period: $3.96 Million**

Description: The Energy Diagnostics and Management (ED&M) Project is the implementation of a comprehensive strategy for customer self-service demand-side management. With the release of Energy Diagnostics and Management Platform, the customer can use Your Account portal to understand their energy bills, how they use and generate energy, rate options, and savings opportunities. In addition to launching new versions of existing online tools, the current Home Energy Report Program has been scaled to 1.5 million residential customers and expanded email HERs to 650,000 existing HER recipients to complement the mail and driver deeper engagement in the online channel. A Business Energy Report (BER) Emerging Technology field test was designed and implemented to determine the impact of monthly reports on Small and Medium Businesses (SMBs). These BERs were developed and provided by Opower and EnerNOC, focused on behavioral interventions, sent by mail, to encourage energy conservation in both gas and electricity. Follow up did not find any gas or electricity savings from the treatments tested.

Funding Source: This project was funded through the EE and DR Balancing Accounts and GRC. Approximate costs listed reflect total budget allocated to project over the duration of the reporting period.

Status: The project was launched in May 2015 and development completed in March 2017. It replaced the existing contract to provide Home Energy Reports and existing My Energy portal functionality. Notable updates during this reporting period include: Adding EV tips and category in the home energy checkup (Dec 2018), adding large commercial and industrial (LCI) customers to the Non-Residential platform for the ED&M tool (May 2019), additional reporting functionality for Non-Res customers (August 2018), and additional releases to make PG&E support more seamless (April – June 2019).

Upcoming Plans (Subject to Change): New Rates and Rate changes for Residential and Non- Residential customers are planned towards the end of 2019 and early 2020. As households continue to increase electricity consumption due to electrification, the HER/BER program, with its proven ability to deliver electric savings, should continue to provide information on ways for customers to achieve electric savings.

Benefits Description: This project provides residential and small and medium non-residential customers with actionable information and personalized recommendations on how they can save energy find the best rate for them and explore DG and EV options. Benefit Category: Engaged Consumer – the project increases customer awareness and engagement in managing their energy usage in an environmentally sustainable and economically efficient manner.

Bill Forecast Alerts (formerly: Energy Alerts)	**Approximate Cost Over Reporting Period:** **$0.024 Million**

Description: The Bill Forecast Alert feature allows customers to set personalized budget thresholds and are notified via email, text, or phone when they are projected to exceed that amount during their monthly billing cycle. Customers with a single premise, with a SmartMeter, on their account, and on a supported rate plan (HG1, HE1, HE6, HEVA, HEVB, HETOUA, HETOUB, HETOUC, G1, E1, E6, , EVA, EVB) are eligible. The following classes of customers are not supported: DA,), and Net Energy Metering (NEM).

Funding Source: This project was originally funded under PG&E's SmartMeter Upgrade Program and received additional funding under GRC's capital fund and expense.

Status: In March of PY 2016 Energy Alerts transitioned into BFAs. BFA replaced the Tier Alerts with an alert that warns customers when they reach their user-specified dollar amount threshold. Customers are subsequently notified with an alert via their channel of choice (email, phone, or text message) when they meet their designated threshold amount up to one day prior to the end of their billing cycle. BFA is only available for residential customers who are SmartMeter read and billed.

Customers could enroll in Energy Alerts, or currently BFA, online via the Your Account web site. During the past few years, PG&E has marketed Energy Alerts and BFA in a similar manner as Customer Web Presentment (CWP) and often in parallel with CWP and Your Account communications. In December 2013, the Your Account homepage was redesigned, which made it easier for customers to connect to other often-used functions, such as analyzing usage, comparing rate plans, and signing up for Energy Alerts. From 2014 through 2018 enrollments continued to increase, most likely due to greater customer awareness of PG&E's digital services accessible through the Your Account website. In December 2017, BFA reactivated Marin Clean Power and Sonoma Clean Energy customers who had been enrolled in BFA prior to transitioning to their Community Choice Aggregators (CCA). Though CCA customers have been ineligible for new BFA enrollments due to rate modelling limitations, PG&E will open enrollment into BFA to new CCA customers in 2019.

In February 2017, PG&E added to its product offering the HUAs program. This program sends out an early warning notification when customers are projected to trigger a surcharge. The High Usage Surcharge is incurred when customers exceed four times their Baseline Allowance. HUA is only available for residential customers with electric service through a SmartMeter and are on eligible tiered rate plans. Similar to BFA, customers could enroll in HUA online via the Your Account website. As part of the implementation of the High Usage Surcharge, PG&E sent letters to customers who were at risk of the surcharge or had incurred it. The HUA program was featured in these compliance letters, which helped drive some of the enrollments into the program.

In 2018, a total of 117,201 customers enrolled in the HUA program with 1,022,319 HUAs sent. These counts also include participants, who are enrolled in other PG&E programs such as CWP, BFA, SmartRate™ and SmartAC. As with BFA, the analysis population excludes SmartAC and SmartRate customers, participants who received alerts on more than one media type, and those who did not receive an alert in 2018. The analysis population was also segmented into singly-enrolled HUA participants and participants dually-enrolled in BFA and HUA. As a result, the HUA analysis population consists of 42,393 singly-enrolled participants and 74,808 dually-enrolled participants, for a total of 117,201 analyzed HUA participants in 2018. Singly enrolled HUA Customers saved $98,000 annually with 2,501 MWh is energy savings.

Benefits Description: Bill Forecast Alert provides enrolled customers with a monthly projected bill amount notification when their current usage pattern is expected to exceed their personalized threshold amount. This alert will help customers adjust their consumption patterns to avoid paying higher energy bills or financially plan for their estimated bill amount.

Benefit Category: Engaged Customer.

Benefits Quantification Methodology: This evaluation was conducted in four phases: data collection, ex post impact estimation, documentation and reporting, and regulatory support and consultation. The data analyzed singly- and dually-enrolled HUA and BFA customers, and calculated Energy Savings and Financial benefits (reported in thousands). Dually-enrolled customers experienced a total of 5,417 MWh of energy savings and $212,000 in financial benefits, singly-enrolled HUA customers experienced 2,501 MWh of energy savings and $98,000 of financial benefits, and singly-enrolled BFA experienced 1,603 MWh of energy savings and $62,000 of financial benefits. To calculate financial benefits for conservation programs, PG&E uses the following formula: Financial benefits = energy savings x avoided generation costs ($39.06/MWh in 2018). The cost figure comes from Appendix A of the Settlement agreement on marginal Cost and Revenue Allocation in Phase II of G&E's 2014 GRC (A.13-04-02). Detailed results, including seasonal usage, comparison group matching, and alert data is found in the SmartMeter Enabled Programs PY 2018 Report and Appendix.

Full Report: PY2018 Evaluation of BFAs and HUAs. CALMAC ID PGE0418 Opinion Dynamics. For further project information, see: OP10 compliance report, Progress on Residential Rate Reform (http://www.cpuc.ca.gov/General.aspx?id=12154).

Share My Data (Customer Data Access) Project	**Approximate Cost Over Reporting Period:** **$2.8 Million***

Description: Under the Customer Data Access (CDA) project, now known as "Share My Data," PG&E developed a platform that provides authorized and secure data to customer-authorized third parties. With the release of CDA Phase 1 functionality, customers could share electric energy usage data with third parties. With the release of the CDA Phase 2 functionality in December 2015, customers could also opt to share one or more categories of information, including usage (e.g., interval usage data for gas consumption), billing (e.g., rate schedules, billing history) and account (e.g., service address). In 2018, PG&E implemented an online authorization process which enables customers to authorize data release via an online platform. This authorization pathway supplements the paper-based form which had previously been the sole means for customers to authorize data release.

Funding Source: This project was funded by the CDA D.13-09-025 through December 2016. As of January 2017, operation and maintenance for this project is funded through GRC. The Click Through Project is funded by D.16-06-008 and covers both Share My Data related updates and specific changes to better support Electric Rule 24 process for DRP. Status: On September 19, 2013, the CPUC approved PG&E's CDA Application (D.13-09-025). PG&E launched Phase 1 of the Share My Data project in March 2015 and Phase 2 in December 2015. On August 25, 2017, the CPUC approved PG&E's Advice Letter (AL) 4992-E in compliance with OP 10 of D.16-06-008 to deliver Click Through with Resolution (Res.) E-4868. PG&E launched Click Through Phase 1 to comply with Res. E-4868 on February 22, 2018 and Phase 2 on June 28, 2018, Expanded Data Set at the end of September, and Phase 3 on November 15, 2018. This project was to provide improvements to the Electric Rule 24 process for DRPs to obtain customer authorization to access the customer's data for direct participation in the CAISO's wholesale market. This also included simplifying the overall electronic authorization process via the Share My Data platform. Upcoming Plans (Subject to Change): There are no upcoming projects related to Share My Data. PG&E submitted an application to the CPUC in compliance with Resolution E-4868, in which it outlines its estimate to implement an Alternative Authorization Solution, proposes its plan to accommodate quick response and to expand click-through to DERs, and a few other enhancements submitted by vendors through the CDA Committee. The Application is pending with the Commission. Other upcoming work includes regular platform O&M and enhancements. Benefits Description: This platform provides PG&E's customers and their selected third-party service providers with a robust means of accessing their energy data in a standardized manner. It also supports the evolution of the energy services industry by providing the data necessary for third parties to develop applications that will help customers manage their energy usage and reduce their monthly energy bills. Benefit Category: Engaged Consumer – the program increases customer awareness and engagement in managing their energy usage in an environmentally sustainable and economically efficient manner.

Energy Data Access	**Approximate Cost Over Reporting Period:** **$0.3 Million**
Description: In Commission D.14-05-016 (Decision), the Commission adopted rules to provide access to energy usage and usage-related data to local governments, academic researchers, and state and federal agencies for specific use cases, while protecting the privacy of customers' personal data. The Decision ordered the utilities to create a Data Request and Release Program to facilitate this access and instructed the utilities to submit an updated data catalog in the Smart Grid Annual Report.[29] Funding Source: Through December 2016, PG&E was tracking the incremental costs associated with implementing this decision in a memorandum account and was seeking authorized recovery of such costs through its GRC proceeding. As of January 2017, operation and maintenance for this project is funded through GRC.	

[29] D.14-05-016, pp. 91-92.

Status: In December 2014, PG&E implemented the Decision requirements, which includes the development of an Energy Data Request Program portal, creation of a Data Request and Release Process, publishing of a data request log (referred to as data catalog in the Decision), publishing of a quarterly energy consumption report by zip code and customer class, and the formation of a statewide Energy Data Access Committee (EDAC). An updated data request log (data catalog) is provided below and summarizes the requests worked on during the period July 1, 2017 through June 30, 2018. The complete log can be viewed on PG&E's website at http://www.pge.com/energydatarequest. The EDAC was required to hold quarterly meetings through December 2016 and thereafter only met on an 'as needed' basis. Minutes from the meetings are posted on the CPUC's EDAC website: http://www.cpuc.ca.gov/General.aspx?id=10151. For further project information see: Quarterly Advice Letters (Latest filing: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4093-G.pdf).

Benefits Description: This program provides energy consumption and energy-related customer data to qualified academic researchers for research purposes, local governments for their climate action plans, and state and federal agencies to fulfill statutory obligations, including low-income participation in EE programs. The data provided is intended to promote EE, DR, and GHG reductions, and advance Smart Grid policy goals.

Benefit Category: Engaged Consumer – this program facilitates access to energy data for local governments, academic researchers, and state and federal government entities needing data to fulfill statutory requirements.

Table 4-1: PG&E ENERGY DATA REQUEST PROGRAM – DATA REQUEST LOG (7/1/2018 – 6/30/2019)

Organization	Requestor Type	Description	Status	Change Date
City of South San Francisco	Local Government	TBD	Paused	6/28/2019
City of Richmond	Local Government	Non-residential usage for 2014-18, by year.	Paused	6/26/2019
UCLA	Academic Researcher	TBD	Paused	6/26/2019
UC Davis Center for Water-EE	Academic Researcher	Interval and identifying information for all customers on agricultural rate schedules in zip codes specified by UC Davis. Also matching PG&E pump test data where available.	Downloaded	6/21/2019
City of Benicia	Local Government	Gas usage monthly, by sector.	Canceled / Withdrawn	6/18/2019
City of Tracy	Local Government	Total usage, by month, for gas and electric, split into Res, Com, Ind, Ag sectors.	Downloaded	5/9/2019
City of Sunnyvale	Local Government	Total usage and billed days, for gas and electric, split into Residential and Non-Residential sectors.	Downloaded	5/9/2019
Duke University	Academic Researcher	NA	Downloaded	4/5/2019

Organization	Requestor Type	Description	Status	Change Date
University of California, Los Angeles	Academic Researcher		Rejected	4/5/2019
University of California, Davis CWEE	Academic Researcher	TBD: need to refine both customer list and data field list.	Paused	4/5/2019
Duke University	Academic Researcher	Anonymized, random sample, residential usage, billing, and program information for PG&E's service territory.	Completed	3/27/2019
Department of Community Services and Dev	Community Services & Development	Average Cost and Average usage for Electricity and Natural Gas for all residential PG&E customers by month, separated by county.	Completed	3/26/2019
City of Fremont	Local Government	Annual electricity and natural gas use for the calendar years 2016 and 2018, separated by residential and nonresidential uses	Completed	2/25/2019
UC Davis Inst. of Transportation Studies	Academic Researcher	Grid data (general).	Canceled / Withdrawn	2/21/2019
Merced CED Department	Local Government	Aggregated gas and electric usage for Unincorporated Merced County, 1/1/2016 - 12/31/2017, for residential and non-residential customers	Downloaded	2/6/2019
Stanford University	Academic Researcher	Daily or Monthly usage by zip code, preferably broken down by on and off peak.	Canceled / Withdrawn	1/24/2019
City of Berkeley	Local Government	Aggregated electric and gas usage for 2018, by month.	Downloaded	1/22/2019
City of Dixon	Local Government	NA	Canceled / Withdrawn	12/31/2018
City of Fremont	Local Government	Annual electricity and natural gas use within the City of Fremont for the calendar year 2017, separated by residential and nonresidential uses.	Downloaded	12/18/2018
City of San Jose	Local Government	Electric and Gas usage, by year, by zip code for 2012-2017.	Downloaded	12/12/2018

Organization	Requestor Type	Description	Status	Change Date
County of Contra Costa	Local Government	Annual electricity and natural gas use within the unincorporated areas of the County of Contra Costa for the calendar year 2017, separated by residential and nonresidential uses	Downloaded	12/7/2018
City of Piedmont	Local Government	Annual electricity and natural gas use within the City/Town of Piedmont for the calendar year 2017, separated by residential and nonresidential uses.	Downloaded	12/7/2018
Alameda County	Local Government	Annual electricity and natural gas use within unincorporated Alameda for the calendar year 2017, separated by residential and nonresidential uses.	Downloaded	10/19/2018
Alameda County	Local Government	Annual electricity and natural gas use for ALL of Alameda County (14 cities and unincorporated areas aggregated) for the calendar year 2017, separated by residential and nonresidential uses	Downloaded	10/19/2018
City of Albany	Local Government	Annual electricity and natural gas use within the City of Albany for the calendar year 2017, separated by residential and nonresidential uses.	Downloaded	10/17/2018
Town of Moraga	Local Government	Annual electricity and natural gas use within the Town of Moraga for Calendar Year 2017, separated by residential and nonresidential uses.	Downloaded	10/17/2018
City of El Cerrito	Local Government	Annual electricity and natural gas use within the City of El Cerrito for the calendar year 2017, separated by residential and nonresidential uses.	Downloaded	10/17/2018

Organization	Requestor Type	Description	Status	Change Date
City of San Pablo	Local Government	Annual electricity and natural gas use within the City of San Pablo for the calendar year 2017, separated by residential and nonresidential use	Downloaded	10/17/2018
City of Fresno District 1	Local Government	Electricity usage for the Fresno Tower District.	Canceled / Withdrawn	9/28/2018
Yale University	Academic Researcher	Usage, billing, program participation, and location data for customers in a series of cities determined by Yale.	Downloaded	9/28/2018
Yale Department of Economics	Academic Researcher	Anonymized monthly electrical usage for solar customers and for a random sample of non-solar users.	Downloaded	9/28/2018
City of Antioch	Local Government	Annual electricity and natural gas use within the City of Antioch for the calendar year 2017, separated by residential and nonresidential uses	Canceled / Withdrawn	9/28/2018
City of Richmond	Local Government	Annual electricity and natural gas use within Richmond for the calendar year 2017, separated by residential and nonresidential uses	Canceled / Withdrawn	9/28/2018
City of San Leandro	Local Government	Annual electricity and natural gas use within the City of San Leandro for the calendar year 2017, separated by residential and non-residential uses.	Canceled / Withdrawn	9/28/2018
City of Union City	Local Government	Annual electricity and natural gas use within the City for the calendar year 2017, separated by residential and nonresidential uses	Canceled / Withdrawn	9/28/2018
City of Livermore	Local Government	Annual electricity and natural gas use within the City of Livermore for the calendar year 2017, separated by residential and nonresidential uses.	Canceled / Withdrawn	9/28/2018
County of Santa Barbara	Local Government	GHG reporting for the unincorporated county, not including Vandenberg AFB, for 2017	Canceled / Withdrawn	9/26/2018

Organization	Requestor Type	Description	Status	Change Date
County of Santa Barbara	Local Government	GHG reporting for the unincorporated county, not including Vandenberg AFB, for 2015	Canceled / Withdrawn	9/26/2018
County of Santa Barbara	Local Government	GHG reporting for the unincorporated county, not including Vandenberg AFB, for 2016	Canceled / Withdrawn	9/26/2018
University of Virginia	Academic Researcher	2012-2017 Interval and billing data for non-residential and multi-family buildings in Alameda, Contra Costa, San Francisco, Sacramento, San Joaquin, Santa Clara, Santa Barbara, San Mateo	Canceled / Withdrawn	9/26/2018
Town of Colma	Local Government	Aggregated usage and emissions information, by customer sector, by year.	Canceled / Withdrawn	9/26/2018
Butte County	Local Government	Aggregated usage and emissions information, by customer sector, by year.	Canceled / Withdrawn	9/26/2018
City of Newark, CA	Local Government	Annual electricity and natural gas use within the City of Newark, CA for the calendar year 2017, separated by residential and nonresidential uses.	Canceled / Withdrawn	9/25/2018
City of Walnut Creek	Local Government	Annual electricity and natural gas use within the City of Walnut Creek for the calendar year 2017, separated by residential and nonresidential uses.	Canceled / Withdrawn	9/25/2018
City of Pleasanton	Local Government	Annual electricity and natural gas use within the City of Pleasanton for the calendar year 2017, separated by residential and non-residential uses.	Canceled / Withdrawn	9/25/2018
City of Concord	Local Government	Annual electricity and natural gas use within the City of Concord for the calendar year 2017, separated by residential and nonresidential uses.	Canceled / Withdrawn	9/25/2018

Organization	Requestor Type	Description	Status	Change Date
City of Emeryville	Local Government	Annual electricity and annual gas use within the City of Emeryville separated by RESIDENTIAL AND NONRESIDENTIAL USAGE.	Canceled / Withdrawn	9/25/2018
City of Hayward	Local Government	Annual electricity and natural gas use within the City of Hayward for the calendar year 2017, separated by residential and nonresidential uses.	Canceled / Withdrawn	9/25/2018
City of Dublin	Local Government	Annual electricity and natural gas use within the City of Dublin for the calendar year 2017, separated by residential and nonresidential uses.	Canceled / Withdrawn	9/19/2018
City of Lafayette	Local Government	Annual electricity and natural gas use within the City of Lafayette for the calendar year 2017, separated by residential and nonresidential uses.	Canceled / Withdrawn	9/19/2018
UC Berkeley	Academic Researcher	Meter level gas and electric energy usage data in daily intervals (gas) or in hourly intervals (electric), Climate Zone, Census Block Group, and EE Program Data for matched residential addresses.	Downloaded	9/13/2018
County of Santa Barbara	Local Government	Aggregated monthly electricity usage (kWh) and the total number of accounts for both residential and commercial (excluding industrial) users	Downloaded	8/17/2018
County of San Luis Obispo	Local Government	Aggregated counts of residents on the CARE rate, by month and year for seven digit zip codes (list provided by the County).	Downloaded	8/13/2018
UCD Center for Water-EE	Academic Researcher	Premise ID (anonymized), Service Agreement ID (anonymized), location information, electric rate schedule and consumption, and EE Program Data	Downloaded	7/18/2018

Organization	Requestor Type	Description	Status	Change Date

Stream My Data – Home and Business Area Network (HAN)	**Approximate Cost Over Reporting Period:** **$0.2 Million**

Description: PG&E's Stream My Data helps customers save energy and money by providing RT electricity data through an energy monitoring device. The device helps a customer understand how and when they are using electricity, as well as the related costs—allowing them to take actions to save energy and money. By connecting an energy monitoring device to the electric SmartMeter for the home or an SMB, the customer can do the following:

1. Monitor your RT Electricity Usage (kilowatt (kW))
2. See your RT Price ($/kWh)
3. Get an Estimated Costs to Date and Estimated Electric Bill This Month
4. Receive DR Event Alerts (SmartRate and Peak Day Pricing (PDP) event alerts)

Funding Source: The funding source was based primarily from GRC funding.

Status: "Stream My Data" aka HAN, continues its service with usage available at all SmartMeter devices, and PRICE information available to A1, A10, A6, E1, E6, and EVA rates. Over the timeframe of November-April, PG&E was unable to provision new SmartMeters with necessary digital certificates for HAN use. This affected customers who had new or swapped meters but wanted to utilize Stream My Data service. Digital certificates have since begun to be distributed to those SmartMeters lacking them.

Commercial energy management solution providers have continued to deploy HAN on a small scale and PG&E continues to support their efforts.

Stream My Data has been revised to enable access to electrical usage for residential solar (Net Energy Metering Standard) SmartMeters. Price information availability remains the same for the limited set of rate plans.

Upcoming Plans (Subject to Change): Stream My Data will continue operation with current feature set levels.

Benefits Description: Customers can use validated HAN devices/technologies to receive RT usage, RT price, and DR signals via their SmartMeter. This improves their energy awareness and helps them adapt their energy consumption or load shifting behaviors to lower their monthly energy bills and makes it easier for customers to participate in DR programs.

Benefit Category: Engaged Consumer – HAN enablement allows customers with SmartMeter interoperable devices/ technologies to synchronize with PG&E's SmartMeter.

Building Benchmarking Portal	**Approximate Cost Over Reporting Period:** **$0.21 Million**

Description: The Building Benchmarking Portal (BBP), created in compliance with Assembly Bill (AB) 802, is a web-based system for building owners, or their authorized agents, to request aggregate whole-building energy usage data uploaded into their Energy Star Portfolio Manager accounts. The BBP is a streamlined service for procuring building energy usage data to assist customers in their benchmarking endeavors.

Funding Source: This project is funded through a memo account (MA). PG&E filed a Tier 2 Advice Letter (AL 3707-G/4829-E) seeking to establish memorandum accounts for gas and electric service. These MAs are being used to record costs incurred to comply with AB 802 and will be submitted in PG&E's GRC 2020 Rate Case. Upon review and approval by the CPUC, PG&E will transfer the AB 802 MA balances to the appropriate balancing accounts, as directed by the Commission, for recovery in rates.

Status: At the end of Q3 in 2019, the BBP has received over 6,000 requests for building energy usage data. Most requests are likely driven by the Building Energy Benchmarking Program administered by the CEC. The Benchmarking Program requires certain buildings to report their building's energy usage data to the CEC. 2019 is the first year that qualifying multi-family buildings are required to submit energy usage data to the CEC, in addition to qualifying commercial buildings which began in 2018.

Upcoming Plans (Subject to Change): No major changes to the BBPl are under review. However, the benchmarking team continues to evaluate updates and process improvements to enhance customer experience and increase the value of the BBP for users.

Benefits Description: The BBP streamlines the procurement of energy data for benchmarking. Additionally, tenant turnover is not nearly as impactful on the benchmarking process. As more building owners benchmark their facilities, it will yield greater visibility into building energy use, and opportunities for customers to improve the performance of their buildings.

Benefit Category: Engaged Customer – By simplifying the authorization process, and designing a more resilient portal, the BBP will allow building owners to more easily track and manage building energy consumption.

Time-Varying Pricing (TVP) Rates	**Approximate Cost Over Reporting Period:** **$7.2 Million**

Description: TVP products, such as PDP, TOU, and SmartRate take advantage of SmartMeter capabilities that are now largely available across PG&E's service territory. Charging customers different rates based on varying system conditions is intended to more closely align retail and wholesale electric prices for generation, as well as create economic incentives for customers to actively manage their energy costs by shifting electricity use from when it costs more to when it costs less. PDP provides between 10-15 MW of load reduction on the hottest days of summer, equaling the load of one Peaker power plant. The SmartMeter has enabled PG&E to cost-effectively offer all customers these types of rate programs which provide significant customer and societal benefits.

Funding Source: This project is funded as part of PG&E's Rate Design Window (D.10-02-032, D.11-05-018, and D.11-11-088 – $97.05 million), 2011 GRC (2011 Phase 1 – $12.61 million), and AMI Cases (D.06-07-027 – $2.07 million).

Status: PG&E continues to administer and offer TVP Rates to all PG&E bundled residential and nonresidential customer classes. Beginning in November 2012, SMB customers with 12 months of SmartMeter data began a mandatory transition to TOU rates and two years later, in 2014, began transitioning to default opt-out PDP. Small Agricultural customers began transitioning to mandatory TOU rates annually starting in March 2013. CPUC D.15-07-001 mandates that PG&E's

residential customers be defaulted to TOU rates, beginning in 2019. Eligible residential customers may also enroll in the SmartRate Program. Enrollment in SmartRate is at 67,000 residential customers as of July 2019 and provides an average of 10-15 MW of load reduction on event days.

Over 439,000 SMB Service Agreements have transitioned to TOU rates in the past seven years. 118,000 Service Agreements are active participants in the PDP Program as of July 2019.

In November 2019, PG&E will begin to offer new non-residential TOU rate plans that shift peak periods to the evening hours on an optional basis. Beginning in November 2020, PG&E will begin to transition remaining eligible customers to these new rate plans with 4-9pm peak period for commercial and industrial customers, and 5-8pm peak for agricultural customers. This shift is being implemented to better align with the cost of energy in the later hours of the day.

Benefit Description: TVP reduces demand during peak summer-time periods, lowering systemwide costs, by enabling customers to save money by shifting load to off-peak times of day. Customers can still use the same amount of energy and reduce their bill by shifting some of their usage to times of lower cost generation.

Benefit Category: Engaged Consumer and Smart Utility – the program increases customer awareness and engagement in managing their energy usage.

4.2.4 Emerging Customer-Side Technology Projects

Automated Demand Response (ADR) Program	**Approximate Cost Over Reporting Period: $2.5 Million**

Description: PG&E's ADR program offers residential, small, medium (SMB) and large commercial and industrial (LC&I) customers an incentive or rebate to install equipment that has the ability to automatically reduce a customer's energy use during DR events without any manual intervention. Specifically, the technology that is incentivized ranges from smart thermostats to complex EMS and agricultural pumps and is provided for customers who agree to participate in either PG&E or third-party eligible DR programs. ADR provides a communication infrastructure that links PG&E's designated third-party head-end control system to either a cloud-based platform or the actual control technologies. PG&E supports commercial customers to develop pre-programmed energy management and curtailment strategies to participate in DR event days.

Funding Source: PG&E's ADR program is authorized through 2023 under D.17-12-003 and further governed under D.18-11-029 which provide a balancing account mechanism.

Status: From 2017 through 2019, PG&E developed the infrastructure to provide residential rebates on smart thermostats for customers who participate in demand response programs. The ADR program has embarked on a project to identify other residential control technologies that could be eligible in the future. The SMB and LC&I customers continue to be supported through a third-party program implementer.

Benefits Description: Customers receive many benefits from deploying automated technologies. Oftentimes, they are also able to take advantage of EE and ADR incentives to offset the cost of the technologies, which can greatly benefit businesses. In addition to the ongoing benefits of energy savings, customers benefit from the ease of participating in DR events without manual intervention. Through DR program participation, typically customers are also compensated to reduce load on DR event days which can provide longer-term benefits to customers. Compensation varies depending on which DR program the customer chooses to participate. Eligible programs range from SmartRate and PDP, which have direct enrollment with PG&E, to the third party/aggregator managed Demand Response Auction Mechanism, CBP and the Excess Supply Side Pilot. Customer compensation can be especially variable when working with an aggregator as the level is decided between the customer and the aggregator.

Benefit Category: Technology Adoption and Customer Engagement – ADR provides rebates and incentives to customers to promote adoption of control technologies that can help them save energy and reduce costs on an ongoing basis. Through participation in a DR program, customers can also provide value to the grid. An overview of associated benefits are provided below:

1. Cumulative kWh benefit from CBP and PDP: 300 MWh
2. GHG Benefit with the 2016 factor from PG&E of 294 lbs of CO_2 per MWh: 88,197
3. Financial Benefit: N/A – the purpose of ADR incentives and rebates is to promote adoption of automated technology that utilizes a specific communication protocol (OpenADR). The benefit of adopting technology that utilizes an open standard versus not (e.g. proprietary smart thermostat or battery management system) ensures that assets will not be stranded should there be an ownership change. The financial aspect of this benefit is not quantifiable at this time.

Smart Thermostat Study	Approximate Cost Over Reporting Period: $55 Thousand

Description: PG&E conducted an Emerging Technologies field assessment to evaluate gross energy savings and effectiveness of EE facilitating features in multiple smart thermostats—Nest, EcoBee3 and Radio Thermostat of America CT50 with EnergyHub service provider—with focus on learning/optimization software, occupancy sensing and geo-location. Behavioral messaging and DR were out of scope. Smart thermostats were professionally installed at no cost to 2,207 residential customers in the North Valley, Stockton and Fresno areas in 2015. Both billing data and manufacturer thermostat usage data was collected over the 24-month monitoring period and used for analysis.

Funding Source: PG&E funded this project using funds authorized under the 2013-2015 EE Program as part of Emerging Technology activities.

Status: In December 2016, a report providing an analysis of the first year's results was posted to the Emerging Technologies Coordinating Council (ETCC) website (https://www.etcc-ca.com/reports/smart-thermostat-study). All three thermostats achieved annual electric savings ranging from 4-5 percent. One of the thermostats tested also achieved annual gas savings. The project's second year of monitoring concluded in the fall of 2017 and a report detailing an analysis of the second year's performance and the results of a survey of the study participants was posted to the ETCC site in March 2018 (https://www.etcc-ca.com/reports/smart-thermostat-study). The results indicate that savings persisted in the second year, although at a somewhat lower level. The consultant concluded that the lower level of savings was due in part to the extreme heat in the second year of the study, and that continuing the study for a second year led to sample attrition making the savings more difficult to detect.

In 2019, PG&E expanded upon the Smart Thermostat study to extrapolate energy savings across all climate zones in California to inform savings estimates in the various climate zones. The analysis was used in the 2019 Smart Thermostat statewide workpaper update. Upcoming Plans (Subject to Change): PG&E may enlist participating smart thermostat study participants to participate in future research. <u>Benefits Description</u>: PG&E leveraged key learnings from this study to add smart thermostats to the EE portfolio in June 2017. Data captured in the Study have been used for the 2019 Smart Thermostat Workpaper Update, informing electric savings values across all California climate zones. <u>Benefit Category</u>: Engaged customer. The latest generation of Smart Thermostat products offers customers easier and more convenient ways to manage their heating, ventilation and air conditioning with improved functionality and integration to other connected devices. Moreover, smart thermostat as the first connected system in line is a way to enable customers to have insight and control over their energy usage pattern.

4.3 Distribution Automation and Reliability Projects

Projects in the Distribution Automation and Reliability category provide capabilities and associated technology enablement to monitor and control the electric distribution system. PG&E continues to focus on technology capabilities to increase the visibility and control enabled by Substation SCADA in the distribution system, continues to deploy FLISR technology projects first introduced by the Cornerstone project, implemented technologies to support the effective consolidation of Distribution Control Centers, and deployed EPIC demonstration projects to further distribution capabilities.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2018 through June 30, 2019 timeframe, unless otherwise noted.

Advanced Distribution Management System (ADMS)	**Approximate Cost Over Reporting Period:** **$7.34 Million**
<u>Description</u>: This project is the first component of a multi-year effort to implement an ADMS, which will integrate several mission critical distribution control center applications that are currently spread across multiple platforms. The ADMS will become part of the core distribution operations technology tools that enable the visibility, control, forecasting, and analysis of a more dynamic grid.	

Advanced Distribution Management System (ADMS)	Approximate Cost Over Reporting Period: $7.34 Million

When fully deployed, the ADMS platform will bring the capabilities of today's Distribution Supervisory, Control and Data Acquisition (D-SCADA) software, DMS, and Outage Management System (OMS) into a single platform. These applications are described below.

D-SCADA: PG&Es D-SCADA system gathers, processes, and displays system-wide operating data to Distribution Operators at control centers. Operators use the system to remotely control and/or operate devices on the distribution network. The D-SCADA system consists of distributed IT network system and server hardware (the SCADA "platform") and a growing number of SCADA-enabled field devices which send and receive real time data over the network.

PG&E's SCADA platform is no longer adequate to support projected growth, evolving cybersecurity threats, or the need for increasing integration with other control center systems. RT-SCADA, the current application managing data exchange between field devices, processors/servers, and displays in the control center, is nearing the end of its useful life and does not have the functionality and cybersecurity features to address future grid conditions, including an increased number of field devices and increased DER penetration. Similarly, the current hardware supporting the SCADA system does not have sufficient processing or storage capacity to address the increasing complexity of the grid, or to support advanced control and analytic applications. A major part of the project is associated with replacing the hardware and software associated with PG&E's D-SCADA platform, migrating data from the existing D-SCADA database to the new ADMS-SCADA database, and programming and testing to ensure that field devices communicate accurately with the ADMS-SCADA application.[30]

DMS: DMS is a system that utilities use to maintain an As-Operated model of the electric distribution grid, can run applications that analyze the grid.

OMS: OMS is a network model-based system that utilities use to identify electrical outage locations and assist in the restoration of power. This system also provides utility customers with updated outage information and is the source for reliability reporting. The accuracy of OMS's identification of outage is dependent on its network model reflecting the actual as-switched state of the distribution system at any given time.

Integrating SCADA, DMS, and OMS into a single, more efficient platform will reduce the potential for operator error, improve cybersecurity risk controls, and enable PG&E to run a new suite of advanced applications that enhance current capabilities associated with safety, reliability, and affordability, and respond to future needs associated with the growth of DERs and complexity from growing wildfire risk.

Funding Source: This project is funded through PG&E's GRC.

Status: PG&E conducted an RFP to evaluate the ADMS software vendor marketplace in 2018 and selected a preferred vendor solution. Subsequently, we developed an implementation plan for the overall ADMS solution deployment. That plan

30 Funding for SCADA replacement and DMS integration was approved in the 2017 GRC. The replacement was scheduled to begin in 2017 and was forecast to be completed in 2021. As further explained below, the start date of the project was pushed back to 2018, and PG&E now forecasts that it will be completed in 2022.

Advanced Distribution Management System (ADMS)	Approximate Cost Over Reporting Period: $7.34 Million

shows the deployment of technology in three releases. Implementation of ADMS SCADA is the first release and is currently in the Analyze/Design phase. This phase is expected to complete in mid-2020.

Upcoming Plans (Subject to Change): PG&E expects to complete the Release 1 Design phase in mid-2019, and subsequently enter the Build phase.

Benefits Description: ADMS delivers the following benefits:

- Safety – Increases ability to manage future cyber security vulnerabilities which are challenges of the existing D-SCADA application.
- Situational Awareness
    - ADMS can estimate the behind the meter load served by DERs, showing operators, the total load consumed as well as output. This load estimation, coupled with some RT telemetry of DERs, can provide operators with estimates that provide actionable information to perform restoration in the event of an outage on a circuit with a high penetration of DERs.
    - ADMS can provide improved filtering and prioritization of alarms for operators, making the operator more efficient when evaluating and addressing grid issues. This is especially important when storms create well above average outage and alarm volume, and operators can be inundated with alarms.
    - ADMS will promote greater awareness of RT grid status by enabling sharing of information contained in the ADMS with wider audiences across utilities. In addition, PG&E looks to "mobilize" ADMS features and allow for more PG&E personnel to have access.
- Training – ADMS has a training simulator that can effectively train existing and new operators. The simulator allows the creation of real-life complex training scenarios that includes SCADA related events and operations, switching management, outage management events (e.g., customer calls, SmartMeter outage notifications, hazards, damage, etc.).
- Operational Efficiency
    - ADMS enables switching submittal, planning, and execution to be a process contained within one application, driving substantial efficiency. ADMS provides the ability for efficient scheduling with "conflict checking" as well as fast development of switch logs, with fully embedded intelligence to verify the switch log's impact, in both real time and study mode.
    - Better load forecasting driving better grid operations: ADMS has a load forecasting engine that develops "operational time horizon" (i.e., 24 hr., 7 day) load forecasts.
    - FLISR expansion and maintenance: FLISR is an advanced application that is part of the ADMS platform. ADMS FLISR will know the topology and capacity of the grid, and the forecasted load. Therefore, ADMS FLISR requires less time to configure than PG&E's existing FLISR, which as a standalone application must manually be configured.

Advanced Distribution Management System (ADMS)	Approximate Cost Over Reporting Period: $7.34 Million

- Reduce utility line losses: ADMS's optimal power flow capabilities can control SCADA-enabled capacitors to minimizing line losses while maintaining power factor and voltage compliance. Reducing line losses lowers GHG emissions and reduces PG&E's energy procurement costs.
- Drive Conservation Voltage Reduction (CVR): ADMS's optimal power flow capabilities can control SCADA-enabled substation transformer load tap changers, line voltage regulators, and capacitors to drive CVR. CVR is a physical effect which reduces the energy consumed by customers' devices. This lowers GHG emissions and reduces PG&E's energy procurement costs.

Benefit Category: Smart Utility

Distribution Substation Supervisory Control and Data Acquisition (SCADA) Program	Approximate Cost Over Reporting Period: $39.6 Million

Description: The Distribution SCADA Program focuses on increasing SCADA penetration and improving reliability for PG&E customers. This program aided in the consolidation of PG&E's Distribution Control Centers, which was completed in 2016. PG&E's goal is to achieve close to 100 percent visibility and control of all critical distribution substation breakers over the next few years, adding or replacing SCADA for approximately 530 substations and approximately 2030 breakers.

Funding Source: GRC

Status: This project is in progress. This project started in March 2011 and is expected to achieve 99% penetration by December 2020. The remaining 1% are projects that are being aligned with other planned major capital projects to take advantage of execution efficiencies. This project has upgraded or replaced SCADA in 495 substations and 1,930 breakers between 2011 through June 2019.

Upcoming Plans (Subject to Change): SCADA Installation program is planned to achieve close to 100 percent visibility and control by 2020 and will transition to focus on proactively executing SCADA replacement program to proactive replace aging assets.

Benefits Description: Increasing SCADA penetration enables improvements in reliability, grid planning, and operations.

Benefit Category: Smart Utility – PG&E's goal of 100 percent visibility using SCADA is expected to reduce outage time, personnel travel, and operations time managing the system. Improved SCADA visibility also provides data to better operate, plan and design the distribution system.

Smart Grid Fault Location, Isolation, and Service Restoration (FLISR)	Approximate Cost Over Reporting Period: $8.03 Million
Description: This project continues the installation of FLISR systems work that was funded in the Cornerstone D.10-06-048. Smart Grid FLISR will expand the implementation of the FLISR system to approximately 30% of the distribution circuits in PG&E system to improve customer service reliability. Funding Source: This project is funded in PG&E's 2017 GRC. Status: This project has been approved. The Smart Grid FLISR project has begun in 2014 and is expected to continue through 2019. Upcoming Plans (Subject to Change): The Smart Grid FLISR project is expected to continue through 2019 with lower rate of expansion during the 2020 GRC (8 circuits per year). Benefit Description: When installed, FLISR can reduce the impact of outages by quickly opening and closing automated switches to reduce what may have been a one- to two-hour outage to less than five minutes. Benefit Category: Smart Utility – the Smart Grid FLISR project improves customer service reliability, installs SCADA devices that provide RT load and voltage data which supports distribution operations and DER/distribution resource integration.	

4.4 Transmission Automation and Reliability Projects

Projects included in the Transmission Automation and Reliability category provide capabilities and associated technology enablement to monitor and control the electric transmission system. Over the past year, PG&E has focused on technology capabilities to improve wide-area monitoring, protection, and control enabled by SCADA in the transmission system, equip operators with the tools necessary to enhance bulk system reliability in coordination with the CAISO and neighboring utilities, and pilot and deploy digital substation capabilities and other Smart Grid and technology.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2018 through June 30, 2019 time period, unless otherwise noted.

Transmission Substation SCADA Program	Approximate Cost Over Reporting Period: $9.2 Million
Description: Under the Transmission Substation SCADA Program, PG&E is in the process of installing new SCADA on the transmission system to provide PG&E's Electric Operations and the CAISO with full visibility into the transmission system,	

significantly improving efficiency and operational flexibility. PG&E's current goal is to achieve close to 100 percent visibility and control of all transmission substations over the next few years, adding or replacing SCADA for approximately 460 substations and approximately 1,950 breakers.

Funding Source: This project is funded under PG&E's Transmission Owner (TO) cases.

Status: This project is currently in progress. The project started in July 2010 and is expected to achieve 98.2% penetration by December 2020. The remaining 1.8 % are projects that are being aligned with other planned major capital projects to take advantage of execution efficiencies. PG&E has added or replaced SCADA at 430 substations and 1,860 breakers from 2011 through June 2019.

Upcoming Plans (Subject to Change): SCADA Installation program is planned to achieve close to 100 percent visibility and control by 2020 and will transition to focus on proactively executing SCADA replacement program to proactive replace aging assets.

Benefit Description: Increasing SCADA penetration enables improvements in reliability, grid planning, and operations.

Benefit Category: Smart Utility – PG&E's goal of 100 percent visibility using SCADA is expected to reduce outage time, personnel travel and operations time managing the system and provide data to better operate and plan the transmission system.

Modular Protection Automation and Control (MPAC) Installation Program	**Approximate Cost Over Reporting Period: $59.2 Million**

Description: The multi-year MPAC Program aims to deploy pre-engineered, fabricated, and standardized control buildings in transmission substations. These activities are performed in an integrated manner with other PG&E projects such as capacity expansion projects, bus conversions, deficiency and aging asset replacement, control room condition improvements, reliability, and control center consolidation efforts.

Funding Source: This project is funded under PG&E's TO cases.

Status: This project is currently in progress. This is an ongoing program which doesn't have a defined end date. The project began in 2005. PG&E has installed and completed 120 MPAC buildings.

Upcoming Plans (Subject to Change): The MPAC program will continue focusing on deploying pre-engineered, fabricated, and standardized control buildings in transmission substations to support other capital projects in an integrated manner, such as capacity expansion projects, bus conversions, deficiency and aging asset replacement, control room condition improvements, reliability, and control center consolidation efforts.

Benefits Description: The program will help improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities. Over the past year, the MPAC Installation Program has avoided $5.2 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $69.8 million.[31]

[31] MPAC benefit totals reflect updated calculations for 2019 Smart Grid Annual Report.

Benefit Category: The program is a Smart Utility project designed to improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities.

Energy Management System (EMS)	Approximate Cost Over Reporting Period: $4.5 Million

Description: The EMS system is utilized by Transmission System Operations (TSO) to monitor and control the transmission system. The system is comprised of several modules which provide different functionality to Operations personnel. PG&E has recently completed upgrades to their hardware and software platform for the existing EMS and is continuing development work on new modules to increase EMS capabilities for System Operator, Dispatchers and Engineering to better analyze, monitor and control the transmission system and meet NERC compliance requirements.

Funding Source: This project is funded primarily under PG&E's TO cases.

Status: Active. EMS went live with new system on 12/2018, however development work continues to further enhance the system's functionality. Development is currently underway. Implementation and Testing for the new software modules will occur by the end of 2019, with further enhancements getting implemented in 2020.

Upcoming Plans (Subject to Change):

- Development of an integrated tool to manually or automatically generate System Restoration and Outage Plans based on RT or study conditions
- Implement Outage scheduler modules to interface with external software for automatic import of scheduled outage information into EMS
- Centralized battery control capability

Benefit Description: Benefits include:

- Improves the ability to perform timely Operational planning analysis to maintain system reliability prior to or during system events, including PSPS.
- Better demonstrate NERC compliance.
- Minimizes 3rd party applications and interfaces to streamline EMS environment architecture, therefore more reliable and easier to maintain.
- Better integration of operational information for more efficient RT monitoring and analysis.

Benefit Category: System Reliability and Operational Efficiency

Synchrophasor Project Realization	Approximate Cost Over Reporting Period: $0.5 Million

Description: Synchrophasor Applications Upgrade project will build on the previous Synchrophasor infrastructure projects, to provide additional functionality to the EMS and integration into RT operations. Data flow into control centers has been enhanced and several use cases for TSO have been implemented. Examples include, post event analysis, phase angle delta monitoring, oscillation detection and monitoring, and model validation. Upcoming enhancements include streaming the data to the Utility Data Network (UDN) (corporate network) and building an application environment on the UDN for enterprise-wide use. Applications on the UDN will include PI, GE PhasorPoint, GE PhasorAnalytics, and others.

Funding Source: This project is funded primarily under PG&E's TO cases.

Status: Active. Communication protocol and transport layer enhancements continuing to support data availability and data quality. Installed PMUs on several 500 kilovolt buses for enhanced state estimation. Working with CAISO, Bonneville Power Administration, Southern California Edison Company (SCE), and SDG&E to improve Synchrophasor data sharing capability.

Upcoming Plans:

a) Establish data stream to the UDN corporate network to enable PI data archival and other enterprise applications

b) Continue expansion of PMU coverage to all 500 kilovolt buses

Benefit Description: Synchrophasor technology provides high resolution grid measurement and more accurate and synchronized measurements in RT. Benefits include:

1. Improvements in PG&E' system models (the basis for the EMS used by Operators) – Accurate model allows identifying true system constraints (voltage, system instability, thermal), improving transmission system performance, and evaluating true limits due to better results for on-line EMS applications supporting state estimation
2. More accurate Control Center understanding of the state of the Grid (Situational Awareness)
3. Faster operator alerts and improved visibility of the fast, dynamic grid conditions
4. Prompt identification of un-damped grid oscillations to prevent outages
5. Quick identification of the location of a grid disturbance for faster response
6. More cohesive system restoration amongst TOs and reliability coordinators
7. Compliance with NERC PRC, MOD, and TOP standards.
8. Compliance with CPUC Rule 21 frequency reporting requirements for SI programs

Benefit Category: System Reliability and Operational Efficiency

4.5 Asset Management and Operational Efficiency Projects

Projects included in the Asset Management (AM) and Operational Efficiency category provide capabilities and associated technology enablement to track and manage asset information (e.g., location, maintenance history, specifications/characteristics), as well as assess and plan asset maintenance, replacement, and capacity enhancements. Over the past year, PG&E has focused on technology capabilities to leverage industry-standard technologies to capture and provide access to accurate, traceable, and verifiable asset information for all stakeholders to support the Electric Operations business.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2018 through June 30, 2019 time period, unless otherwise noted.

Network Supervisory Control and Data Acquisition (SCADA) Monitoring Project	**Approximate Cost Over Reporting Period:** **2018 $9.3 Millions** **2019 $7.7 Millions**
Description: The project is installing new monitoring and control systems on the downtown San Francisco and Oakland secondary network systems including full remote control on network protectors (including remote setting of relays), and primary switches. The monitoring itself includes voltages, currents, temperature, oil level, and chamber pressures. For vaults, the monitoring system includes SCADA battery, water detection and may include others such as DG monitoring depending on future needs and feasibility. RT data collected from the equipment is used for triggering of alarms, and for equipment condition assessment as part of the Condition-Based Maintenance (CBM) system for O&M activities. The data is also used for AM decisions on maintenance and replacement of network equipment. The new SCADA system has remote operating capabilities that include network protector open/close and station transfer trip of the network protectors for feeder clearances. Funding Source: This project is funded by PG&E's 2014 and 2017 GRC filings and currently filed in the 2020 GRC. Status: This project is currently in progress. PG&E has a total of 12 network groups. Five network groups are complete (Z-34-1, Z-34-2, Z-1, Y-4, Y-3) with two additional network groups (Y-2, and Y-1) in progress. These completed network groups have been added to the PI Historian system which is the data accumulator for all the SCADA information. This data in turn is coupled with the CBM system described above which allows PG&E to transition from time based to condition-based replacement and maintenance. This results in a safer system while at the same time generating savings through deferring work until the condition of the equipment warrants. Upcoming Plans (Subject to Change): Continue with this project with installation of approximately one network group per year. Planned overall completion by 2024. Benefit Description: The new control features included as part of this project will improve personnel safety and overall system operability. Benefit Category: Smart Utility – This project provides information for PG&E to better manage its assets and make informed maintenance, repair and upgrade decisions.	

Wind Loading Assessments	Approximate Cost Over Reporting Period: $.80 Million

Description: Develop a scalable program to evaluate structural integrity across all Distribution poles (approx. 2.3 Million) over a 5-year period. Geo-correct pole locations using available LiDAR from Vegetation Management efforts. Objectives of this project include a greater understanding of failure modes, common repository of data gathered, and effectively updating the workflow and asset systems (GIS, SAP) to align with new data strategies. Wind loading segmentation will be performed to identify the wind loading of each asset on a support structure and integrate findings into the appropriate systems.

Funding Source: This is Electric Line of Business funded.

Status: Finishing Plan Analyze. Completing requirements, use cases and high-level architecture. Working on the design for the integration of LCI data to production. Planning the update of Ocalc to version 6.

Benefits Description:

1. Meet 100% of compliance requirement; comply with CPUC GO 95 Rule 44.1, 44.2
2. Accurate and timely mapping of poles into Electric Distribution GIS
3. Improved business and compliance tracking, reporting and document retention due to data integration
4. Integration with enterprise systems, ensuring data synchronization
5. System model to indicate wood poles that need additional attention
6. Starting point automated individual pole modeling

Benefit Category: System Reliability and Operational Efficiency

STAR for Transmission Line	Approximate Cost Over Reporting Period: $1.96 Million

Description: Currently, risk scoring for ET assets is handled on an ad-hoc, manual basis. Currently, asset strategists compile data manually from various data sources and prioritize asset replacement using spreadsheets and anecdotal experience. This legacy process is laborious, prone to data quality issues, static, and hard to reproduce on an ongoing basis. For ET efforts related to WSIP, there is a need for risk-ranked lists at the component level, to execute inspection and repairs on the highest risk transmission assets to minimize failures leading to potential ignitions and outages. A systemic limitation for achieving a robust analytics process for ET risk is a lack of a centralized repository of sanitized, standardized asset data. There is currently no central repository for asset data, data is currently stored in siloed locations. Best practice would be to centralize and standardize asset data.

In contrast to the highly manual risk scoring done today, executed at the project or portfolio-level, the System Tool for Asset Risk (STAR) platform will enable risk scoring and asset health evaluations to be applied at an individual-asset basis for major Electric assets across the whole PG&E territory. STAR will enable consistent and automatic compilation of this information so that AM can focus on improving asset replacement, maintenance and inspection strategies and asset health, failure, and risk model sophistication. The project also enables the ability to analyze likelihood of asset failure, and in the event of an asset failure, what is the consequence from a public safety and reliability standpoint.

Proposed Scope:

1. Develop data connections to Amazon Web Services (AWS) cloud to enhance data quality (GIS, SAP, Customer Care and Billing (CC&B), wires down database, etc.)
2. Risk rank work package of ET components, assets, structures, circuits to inform inspection and repair work planning
3. Set operation parameters to inform PSPS (wind speed, gust speed, humidity, prob of ignition, spread model, damage consequence, population, egress route)
4. Predictive asset failure analysis
5. Remaining Asset lifecycle NPV to inform repair vs replace decisions
6. Establish STAR as the central repository for transmission asset and risk data (i.e.. veg management LiDAR, Asset Performance Center, enhanced physical and drone inspection data, meteorology, CCB, WSOC)

Funding Source: WSIP / IT Book of Work (mixed)

Status: In development

Benefits Description: 05 - ETD Wildfire: The STAR platform will enable understanding of where asset failures may result in severe impacts due to wildfire ignition. The platform will enable risk-based management for vegetation and overhead conductors as done for poles previously. 03 - Records and Information Management: STAR will help Electric AM maintain consistent and accurate records of asset health and risk scoring for T&D assets.

Benefit Category: System Reliability and Operational Efficiency

STAR for Electric Distribution Hardening	**Approximate Cost Over Reporting Period: $1.43 Million**

Description: Climate change has created a new normal with heightened risks created by wildfires, increased storm activity, drought. Investments need to be made regarding system hardening to ensure heightened levels of safety, risk reduction and resiliency. Electric AM has planned the first 1000 miles of hardening work to be executed in 2019 using a manual, ad-hoc analysis. This current method of identifying lines which need to be hardened is not data driven and does not create a levelized, re-producible risk analysis. There is a need to have a system wherein risk analysis is conducted across the entire system on a standardized and levelized basis.

STAR to provide a risk ranked analysis the electric distribution system to inform 2020 work planning. Specifically, STAR will identify the top 650 assets based on risk. Parameters will be captured regarding what the possible drivers for hardening and data connections to the salient data sources housing that data.

Proposed Scope:

1. Develop risk model parameters for hardening

2. Develop data connections to AWS cloud to enhance data quality (GIS, SAP, CC&B, wires down database, etc.)
3. Informing work based on enhanced data sets, providing a risk-ranked asset master data set back to Electric Distribution asset strategists to inform work prioritization
4. Provide analytics identifying the top 650 assets based on risk

Funding Source: WSIP / IT Book of Work (mixed)

Status: Active

Benefits Description: 05 - ETD Wildfire: The STAR platform will enable understanding of where asset failures may result in severe impacts due to wildfire ignition. The platform will enable risk-based management for vegetation and overhead conductors as done for poles previously.

12 – Distribution Overhead Conductor Primary: The STAR product will improve health and risk scoring for Distribution overhead conductors and inform the proactive inspection and replacement programs to manage overhead conductor risk.

03 - Records and Information Management: STAR will help Electric AM maintain consistent and accurate records of asset health and risk scoring for T&D assets.

Benefit Category: System Reliability and Operational Efficiency

4.6 Smart Grid Foundational and Cross-Cutting Technology Projects

Foundational and cross-cutting projects are necessary building blocks for the development of the Smart Grid, such as grid communications, control and monitoring systems, and data management and analytics. An integrated approach in the design and development of these grid technologies will help ensure that the Smart Grid will deliver the greatest possible benefits to all stakeholder, including customers, and help ensure that the electric distribution grid will be able to accommodate high penetrations of DERs while maintaining or enhancing grid stability, resilience, and efficiency. Two foundational technology areas we report progress on in this report are integrated telecommunication systems and DERMS.

PG&E's grid modernization vision, enabled by Smart Grid investments, are largely informed by the work done through the **EPIC**. Phase 3 of the PG&E's EPIC program (2018-2020) kicked off in February 2019.

Advanced technology testing and standards certification in a realistic demonstration environment are essential before a new manufacturer's technology or product can be deployed onto the electric grid. This enables the risks associated with new technologies to be mitigated and controlled, and helps the IOUs maximize technology performance and interoperability prior to deployment.

Smart Grid foundational and cross-cutting technology development are driven by several state and federal laws and regulatory orders including SB 17, Energy Independence and Security Act, CPUC D.10-06-047, AB 32 and Executive Order S-305, SB 078 and SB X1-2.

Workforce development and advanced technology training enables the successful deployment of new technologies, ensuring that the IOUs' workforces are prepared to make use of new technologies.

Integrated Grid Communications Systems

Integrated grid telecommunications systems are a key foundational technology to achieve the grid reliability, flexibility, resiliency and security required to realize the full potential of the Smart Grid. These systems enable sensors, metering, maintenance, and grid asset control networks to allow the exchange of information required to provide real or near-real time operational visibility across the grid. In the mid- to long-term, integrated and cross cutting systems would enable information exchange with the IOU, service partners and customers using secure networks, and to enable new markets for ancillary energy services. Data management and analytics projects will improve the IOU's ability to utilize vast new streams of data from T&D automation and SmartMeter devices for improved operations, planning, AM, and enhanced services for customers.

EPIC Projects

The EPIC projects undertaken by PG&E in the area of Technology Demonstration and Deployment produce electricity ratepayer benefits in the form of increased reliability, improved safety, and/or reduced electricity costs. Projects fall into one of the following four subject areas: (i) Renewables and DERs; (ii) Grid Modernization and Optimization; (iii) Customer Service and Enablement; and (iv) Cross-Cutting/Foundational. EPIC projects that completed during the July 1, 2018 to June 30, 2019 reporting period include:

- Epic 2.02, *DERMS*: DERMS are software systems required to monitor and coordinate the control of various types of DERs, required for the effective and reliable management of the grid with high levels of DER penetration, particularly third-party-aggregated DG and storage resources. Development, testing and demonstrations of DERMS will further California's goals to adopt higher amounts of DERs on the grid while providing operators with the necessary control mechanisms to operate the increasingly complex distribution grid safely, reliably and effectively, while at the same time enabling new value streams from DERs. However, due to the relative novelty of this technology, commercially-tested viable solutions do not currently exist.

  This demo project successfully demonstrated the potential for this technology to provide the functionality to monitor and control DERs; to manage system constraints; and to evaluate the potential value of DER flexibility to the grid. Immediate next steps were identified in deploying foundational utility capabilities, key barriers to scale, and future research and development opportunities related to incorporating DERs into utility operations.

- EPIC 2.03A, *Test Capabilities of Customer-Sited Behind the Meter SI* demonstrated basic technical functionality of SI autonomous functions designed to mitigate local voltage issues associated with high DER penetration and characterized remaining hurdles to scaled SI deployment for grid support. The project characterized remaining hurdles to scaled SI deployment for grid support.
- EPIC 2.05, *Inertia Response Emulation for DG Impact Improvement*, gave a more definitive form to a looming issue facing the evolving power system, namely that a high penetration level of renewable energy significantly decreases the inertia of the PG&E transmission system and increases the occurrence of frequency violations during contingency scenarios. The project focused on clarifying the various functions of synthetic inertia and understanding the opportunities and limitations for obtaining these inertia functions from Inverter-based Renewable Generation (IRG) resources to benefit the electric grid.

- EPIC 2.14, *Automatically Map Phasing Information*, investigated analytical methods to determine phase identification (Phase ID) and meter-to-transformer mapping and determined market readiness for meter connectivity solutions. Accurate phasing information is required for the safe and efficient integration of DERs. Accurate meter-to-transformer connectivity information is needed to ensure proper transformer loading levels.
- A provisional patent was filed in January 2019 resulting from work on *EPIC 2.22, Demand Reduction Through Targeted Data Analytics.* As utilities accumulate increasingly large data sets, and as the introduction of customer owned DERs introduces new types of data and challenges, the importance of processing that data into actionable insights will be critical. This project developed and demonstrated an affordable and scalable solution that positions PG&E as the industry leader in integrating DERs into Distribution Planning, by optimally identifying where targeted procurement of DERs can have grid benefits.

Phase 3 of the PG&E's EPIC program includes 41 specific projects, including the following which are already underway:

- EPIC 3.03 – *Advanced DERMS and ADMS* - This project will design, procure, and deploy a prototype of an enterprise DERMS platform to develop a cost effective non-SCADA solution for providing situational awareness and control capabilities for operators to manage DERS, dispatch DER Registration data requests and monitor SI-based DERs through head-end platform, and provide an interface to dispatch DERs as a remote grid and NWA solution.

- EPIC 3.11, *Multi-use MG*, will enable a multi-customer MG within the Arcata-Eureka Airport business community and will incorporate four PG&E and Redwood Coast Energy Authority customers. The project will design and develop control specifications and provide SCADA integration to maintain visibility and operational control of the MG in grid-connected and islanded modes and will help satisfy the community's demand for enhanced resilience of their power supply.

MGs contribute to grid resilience by providing critical services to localized communities when isolated (“islanded”) from the larger grid during emergencies.

- EPIC 3.20, *Predictive Maintenance.* Assets experience wear and tear, and eventually break down. The most passive strategy is to wait for the equipment failure to address. An already-implemented improvement on this strategy is condition-based maintenance, and schedule maintenance using heuristics regarding expected useful life and level of utilization. This project would move one step further, to detect the signs of near-failure equipment through use of existing data sources such as AMI, PI, GIS, and weather. The project objective is to develop an analytical model in conjunction with existing PG&E data sets to predictively identify distribution equipment failures.

<table>
<tr><th>Electric Program Investment Charge (EPIC) Program</th><th>Approximate Cost Over Reporting Period:
$10.2 Million</th></tr>
<tr><td colspan="2">Description: The EPIC program provides funding to cost-effectively develop and demonstrate promising new technologies which can advance the company’s core values of Safety, Reliability, and Affordability and determine their applicability to address future challenges. Additionally, the main goals of EPIC align closely with PG&E’s grid modernization vision, which drives the advancement of innovative technologies that support PG&E’s core values and an evolving grid. This vision calls for a secure, reliable, and resilient platform that enables continued gains for clean-energy technology to increase customer choice, prepare for climate change impacts and meet state policy goals. EPIC funded projects that are executed by PG&E are focused on four key areas: Renewables and DER Integration; Grid Modernization and Optimization; Customer Service and Enablement; and Cross-Cutting and Foundational Strategy. The program is currently authorized at the state level for three cycles, each cycle is three years:

• EPIC 1 (2014-2016): On November 19, 2013, the CPUC issued D.13-11-025, which authorized the first triennial investment period of 2012-2014 (referred to as EPIC 1).

• EPIC 2 (2015-2017): On April 15, 2015, the CPUC issued D.15 04 020, which approved the second triennial investment plan period of 2015 2017 (referred to as EPIC 2). PG&E’s EPIC 2 application included 30 potential projects. On August 10, 2017, the CPUC issued Res. E-4863, which approved two of the six new EPIC projects proposed by PG&E via a Tier 3 AL 5015-E filed on February 7, 2017, between triennial EPIC Applications as permitted by D.15-09-005.

• EPIC 3 (2018-2020): On April 28, 2017, PG&E filed its A.17-04-028 for the third triennial investment plan period of 2018-2020 (referred to as EPIC 3). PG&E’s EPIC 3 application included 41 potential projects. On October 25, 2018, the CPUC issued D. 18-10-052 which approved the third triennial investment plan period of 2018-2020.

For more information on the CPUC EPIC decisions please visit www.pge.com/epic.</td></tr>
</table>

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $10.2 Million

Project status: Information about PG&E's EPIC projects can be found in PG&E's EPIC 2018 Annual Report, which was filed on February 28, 2019, and can be found on PG&E's website at www.pge.com/epic. All final reports for projects that are complete are publicly available at the same site.

Funding Source: The EPIC 1 Program is authorized via D.12-05-037, and the EPIC 2 Program via D.15-04-020. The Commission authorized the three IOUs to collect funding for the EPIC Program in the total amount of $162 million annually beginning January 1, 2013 and continuing through December 31, 2020. The total collection amount was adjusted on January 1, 2015 to $169.9 million annually, commensurate with the average change in the Consumer Price Index, and this adjustment will occur again. PG&E's share is 50.1 percent or approximately $81 million dollars annually. PG&E sends 80 percent of these funds to the CEC, for their use in addressing EPIC goals. The remaining 20 percent is retained by PG&E to run technology demonstrations. Note: costs reflected in this report reflect PG&E expended costs over the reporting period of July 2018 – June 30,2019. No CEC funds are included.

Status: Through the course of the reporting period, PG&E's EPIC 1 and 2 Programs made significant progress and achieved noteworthy successes on many of the projects. Of the thirty-six projects started across EPIC 1 and EPIC 2, a total of thirty-three EPIC projects have completed. Eleven of these thirty-three projects completed within this reporting period, all of them EPIC 2 projects.

Projects completed during the reporting period can be found in the appendix. Upon completion of these projects, PG&E will leverage learnings and may operationalize associated results, where applicable and cost-effective. The results of PG&E's technology demonstrations are also highly applicable to other industry stakeholders. For example, given the significant DER growth, the opportunities for utilities to partner with technology companies will continue to grow and be a key component of developing future capabilities.

In 2019, PG&E will continue to execute in-progress projects, including one EPIC 1 project and two EPIC 2 projects. PG&E also has begun execution of several EPIC 3 projects.

EPIC 1

In the first triennial cycle, the EPIC 1 portfolio demonstrated PG&E's ability to adopt a new model for managing, aligning, tracking and executing RD&D activities. This portfolio covered a wide spectrum of technologies that help make the electric grid safer, more reliable and more affordable for customers.

EPIC 2

The projects from EPIC 2 are even more focused on long-term strategic objectives and in many cases, are built on the foundation of previous technology investments. Additionally, in EPIC 2, PG&E further explored opportunities to leverage synergies between projects with similar objectives to drive the maximum benefit from the overall technology demonstration at the lowest possible cost to customers. As an example, when feasible, this approach can include sharing resources while also exploring the integration challenges of how the technologies may interact, which will become increasingly important in the future high-DER connected grid.

EPIC 3

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $10.2 Million

Given the impacts of climate change, EPIC 3 will have an increased focus on safety and resiliency. With the climate induced challenges of increasing wildfires and extreme weather events, increased grid visibility and advanced technology driven operations are key. New EPIC technology demonstrations contained within this program cycle can help build on past projects, meet emerging grid needs and help address the threat of climate change, and ensure that the customers and the state can leverage the maximum benefit of this program.

Some of PG&E's achievements in EPIC 1 and 2 have also enabled PG&E to file four full patents and one provisional patent to date:

- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities*: Patent for the development of the Smart Pole Meter
- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities*: Patent for the development of the Smart Pole Meter Socket
- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities*: Patent for an algorithm to help identify downed wires
- *EPIC 1.21 – Pilot Methods for Automatic Identification of Distributed Energy Resources (Such as Solar PV) as They Interconnect to the Grid to Improve Safety & Reliability*: Patent for an algorithm which can detect unauthorized PV interconnections.
- *EPIC 2.26 – Customer and Distribution Automation Open Architecture Devices:* Patent for algorithms to communicate and control edge devices through the AMI network.
- *EPIC 2.29 – Mobile Meter Applications (NextGen Meter – NGM):* Patent on mobile meter with modular housing/board assembly

One additional provisional patent was also filed in January 2019 for the following EPIC project:

- *EPIC 2.22 - Demand Reduction Through Targeted Data Analytics:* Provisional patent for system and server for parallel processing mixed integer programs for load management.

These patents may provide potential future revenue generating opportunities that would be shared with PG&E's customers and shareholders,[32] and ultimately support improved affordability if the patents lead to increased revenue. PG&E continues to consider opportunities to license patents, as well as opportunities to identify additional IP in these and other projects.

Through the EPIC projects, PG&E has collaborated with national laboratories, universities, other utilities, third-parties, etc. Examples of collaboration in this reporting period include:

32 The revenue sharing mechanism is based on the guidance provided in CPUC D.13-110-25 OP 34, which states "(IOUs) must apply a 75 percent/25 percent (ratepayer/shareholder) revenue sharing mechanism for net revenues (from future or ongoing r60-62oyalties, license fees, and other "financial benefits of Intellectual Property (IP)") related to financial benefits of IP that was developed under IOU contracts with EPIC funds."

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $10.2 Million
• *EPIC 2.03A - Test Smart Inverter Enhanced Capabilities – Photovoltaics (PV):* The effort evaluated the grid impacts of PV SIs through two field demonstrations and used PG&E laboratory facilities to evaluate the ability of multiple vendors' SI products to execute Rule 21 SI functions. The project also employed the Electric Power Research Institute to model SI performance and economic analysis on simulated PG&E distribution feeders. EPIC 2.03A findings demonstrated basic technical functionality of SI autonomous functions designed to mitigate local voltage issues associated with high DER penetration and characterized remaining hurdles to scaled SI deployment for grid support. The findings from this project on the potential use of SI autonomous capabilities to support local voltage are expected to be valuable for distribution grid operations, electric generation interconnection, distribution planning, and customer programs. Learnings from this technology demonstration can inform process changes and utility requirements needed to successfully integrate renewable resources controlled by SIs, specifically during the interconnection process. Learnings can also inform the DRP and Integrated Distributed Energy Resource (IDER) proceedings, including Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework, ongoing Rule 21 Order Instituting Rulemaking (OIR), and Grid Modernization Planning filings. SIs can help to better integrate renewables, and, therefore, advance California energy policy to increase the amounts of renewable and Distributed Generation (DG) on the grid. • *EPIC 2.05 – Inertia Response Emulation for DG Impact Improvement*: This project focused on clarifying the various functions of synthetic inertia and understanding the opportunities and limitations for obtaining these inertia functions from IRG resources to benefit the electric grid. This included understanding how these synthetic inertia functions relate to the level of IRG deployment that the system can support. The team worked with the National Renewable Energy Laboratory (NREL) on modeling, simulation, and hardware testing of inertia response capabilities and their impact on the distribution and transmission systems. NREL's unique ability to test equipment aligned well with the goals of this project to demonstrate the capability to emulate inertia injection and support primary frequency control using energy storage and SI technologies. Ultimately, this could mitigate potential impacts due to the loss of inertia from large-scale centralized generation on the grid. The recommendations on future equipment performance requirements could help inform grid requirements such as NERC's issuance of 2018 reliability guidelines (2018) as well as the California Electric Rule 21 SI provisions, to address reliability issues with inverter-based resources like PV and energy storage. Equipment standards such as IEEE 15473 for inverters are also evolving and could evolve based on a more complete understanding of synthetic inertia. • *EPIC 2.14 – Automatically Map Phasing Information:* This project partnered with the University of California Riverside to test an alternate algorithm-based approach using AMI and other data sources to determine the assignment of phases to meters and transformers, which was evaluated against other solutions demonstrated in the project. In addition to the achievements highlighted above, it is equally important to recognize the value of EPIC in determining that a project is not ready to scale. The results of a number of EPIC projects found that more data, analysis, or technology advancement is necessary before the technology demonstrated is considered for	

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $10.2 Million

adoption on a larger scale, which ultimately supports affordability for customers by not adopting the technology at scale before refinements are made to make the technology more viable.

Next Steps for EPIC Investment Plan

PG&E, in conjunction with the other EPIC Administrators, will continue to host stakeholder workshops in 2019. These industry events will continue to focus on the sharing of progress, results, and future plans, improving coordination and understanding among the various stakeholders in the EPIC Program while raising awareness and visibility of EPIC investments and promoting program transparency. PG&E will also continue to promote the EPIC Program through participation in both internal and external public forums and other industry events.

Technology innovation programs like EPIC are critical to continued advancement of the grid, both to enable increased customer choice and further California's clean energy objectives as well as to increase safety and resiliency in light of climate change. Never has there been a time where innovation plays a more critical role to the future of our grid, and we need to act quickly to meet these opportunities head on. PG&E is excited to embark on new technology demonstrations which can help keep continuity on past projects, meet emerging grid needs and California policy objectives, and ensure that the customers and the state can leverage the maximum benefit of this program.

Telecommunications Architecture	Approximate Cost Over Reporting Period: $1.309 Million

Description: Telecommunications Architecture allows PG&E to meet near-term and long-term telecommunications needs by developing and implementing a multi-tier, multi-service telecommunications infrastructure architecture, consisting of a core and an edge network. Smart Grid projects require an exponential increase in the ability for customers, markets and utilities to securely and reliably communicate on a near RT basis. New communication models include customer to utility, customer to market, and smart "equipment to equipment." PG&E's telecommunication infrastructure continues to be enhanced to facilitate increased communications and be developed in a systematic, economic manner that allows for re-use of communications infrastructure.

A blend of technologies will be needed to address the diverse performance needs and geography of the PG&E service territory. Increased SCADA density, PMUs, cyber security, and network management requirements will drive capacity, latency, and quality of service requirements that must be built into future networks.

Funding Source: This project is being funded in PG&E's 2011, 2014 and 2017 GRCs.

Status: We are continuing to consolidate the IP network edge, leveraging the completed MPLS core, to further reduce the devices in the IP network and bring the multi-service, multi-platform capability to the edge of the network. Migration off of legacy Time Division Multiplexing based lease services has been halted in the field. Testing is underway validating that IP based services from Telephone Service Providers are capable of delivering critical PG&E applications, and meeting service level requirements. Wireless edge technologies (Field Area Network (FAN)) have moved out of pilot stage and into full production.

Upcoming Plans (Subject to Change): PG&E will continue to consolidate remaining core and edge network technologies onto the MPLS and FAN to further reduce the device count in our networks which enhances functionality, manageability as well as security. This action is foundational in nature and targeted to meet the anticipated growth in grid devices (PG&E and DERs) which are on the rise in an accelerated fashion. These grid devices will be enabling higher resolution of grid performance and enhanced application to manage DERs, automation programs and support the CWSP.

Benefits Description: No hard benefits have been estimated for this project. As a result of successfully completing the MPLS project, PG&E has forecast soft benefits (or avoided costs) by reducing the number of routers required for asset lifecycle/replacement and their corresponding SmartNet licenses.

Benefit Category: Engaged Consumer, Smart Markets and Smart Utility – Cross-cutting initiatives apply across all three segments.

Workforce Development and Technology Training	**Approximate Cost Over Reporting Period:** **N/A**

Description: The evolution of the electric grid includes much more distributed intelligence, i.e., Smart Grid. PG&E supports this evolution by developing training in a wide variety of grid-related topics, all of which include elements of distributed intelligence, and offering them to the general workforce, targeting those who can use the information most effectively.

Funding Source: This work is funded through PG&E's GRCs.

Status: PG&E is continuing to enhance workforce skills to support a smarter, more integrated grid. Between 7/1/2018 and 6/30/2019 PG&E offered 27 separate workforce education classes covering grid-related subjects through our Pacific Energy Center (PEC). A total of 1,109 attendees participated in these classes. Examples of class topics included:

Demand Response: Basic Concepts, Programs, and Site Assessment
DR can be a significant part of the energy picture for many commercial and industrial facilities, and an important way to lower energy costs. This class covers the basic concepts that building owners and facilities managers need to know to determine if and how DR might be applied to their building(s).

PV + Batteries: Integrating Storage with Grid-Tied PV Systems
As batteries become better and cheaper they are increasingly being used in grid-tied solar electric systems. This course covers the latest in battery technology and how batteries of various sizes are integrated into PV systems, covering basic concepts, design criteria, and financials.

Benefit Description: PG&E's training helps develop the skilled workforce necessary to evolve the electrical grid and meet the energy goals of the state of California.

Benefit Category: Engaged Consumer, Smart Markets and Smart Utility – Cross-cutting initiatives apply across all three segments.

Supplier Diversity	Approximate Cost Over Reporting Period: N/A
Description: Throughout the process of identifying qualified suppliers to participate in the initial testing and limited pilots, PG&E emphasized the criticality of diverse supplier inclusion. PG&E continues to highlight the importance of education, mentoring and careful planning for the full participation of DBEs as business solution partners and subcontractors over the life of this program. As reference, the definition for Diverse Supplier includes: Small Business Enterprises); Women, Minority and Disabled Veteran Business Enterprises; and Lesbian, Gay, Bisexual, and Transgender Business Enterprises. Qualifying vendors must be certified by the CPUC Clearinghouse as follows: • Small Business Enterprises must be registered as a small business with a state or federal agency (e.g., California Department of General Services or Small Business Administration); • Women- and minority-owned businesses must be certified by the CPUC's Supplier Clearinghouse; • Service-disabled veteran-owned businesses must be certified by the California Department of General Services; and • Lesbian, gay, bisexual and transgender-owned businesses must be certified by the National Gay and Lesbian Chamber of Commerce (NGLCC®). As part of the planning and education effort, PG&E provided specific Smart Grid and general business opportunities to DBEs, including: • DBE supplier development opportunities through PG&E's Technical Assistance Program, which include ISO 9001 and ISO 14001 certification training scholarships, DBE sponsorships to select industry trade shows, invitations to matchmaking events and other educational workshops.	

4.7 Customer Outreach & Engagement

In its March 2012 Smart Grid Workshop Report, CPUC Staff requested the following information to be included in the IOUs' Smart Grid Annual Reports:

1. Timeline that connects specific projects with specific marketing and outreach efforts, and
2. Specific steps to overcome roadblocks, as identified in the workshops and included in this report.[33]

[33] See Smart Grid Workshop Report: Staff Comments and Recommendations, March 1, 2012, p. 10.

As requested by CPUC Staff, PG&E is providing marketing and outreach information using the sample template in Appendix 1 to the Smart Grid Workshop Report as follows:

Timeline: PG&E has adapted the CPUC Staff's template to reflect the existing and planned work that is related to the Smart Grid, including approved initiatives in place that meet the customer objectives outlined in SB 17 and D.10-06-047. Since the Marketing, Education, and Outreach proposal in the Smart Grid pilot deployment A.11-11-017 was denied, the only outreach that provides support to the Smart Grid initiative is conducted through funding approvals of individual program and their initiatives as listed in Table 4-2.

Initiative Detail: For each of the project areas identified in the Customer Engagement timeline, PG&E has provided detail on existing or proposed outreach and resources, tools, and rates available to customers in accordance with the proposed template from the Commission's Smart Grid Workshop Report.

Table 4-2 below provides an annual illustration of PG&E's customer engagement timeline.

Customer Engagement Timeline - Table 4-2	2014	2015	2016	2017	2018	2019
Energy Management Enablement Tools:						
PG&E Online Account Web Tools	X	X	X	X	X	X
Universal Audit Tools (UAT)	X	X	X	X	X	X
Energy Usage Alerts	X	X	X	X	X	X
Home Energy Reports	X	X	X	X	X	X
Third-Party CDA Tools (e.g., Share My Data, CDA)	X	X	X	X	X	X
EPIC*				X	X	X
Behind-the-Meter (Customer Premise) Devices:						
SmartAC	X	X	X	X	X	X
DG (Solar Water Heating, Solar PV, etc.)	X	X	X	X	X	X
HAN; Local Area Network; Smart Thermostat, etc.	X	X	X	X		X
EV Supply Equipment	X	X	X	X	X	X
Rates Options:						
SmartRate and Related Residential Time Varying Rates	X	X	X	X	X	X
TOU	X	X	X	X	X	X
PDP	X	X	X	X	X	X
EV Rates	X	X	X	X	X	X

* Various EPIC demonstration projects have some component of customer outreach/marketing.	

EPIC Investment Planning Phase

During the up-front investment planning phase of each EPIC cycle, PG&E collaborates with the other IOUs to share with stakeholders sources and databases on R&D projects being undertaken by other entities[34]. The goal is to help identify EPIC project needs, coordinate investment plans and ensure avoidance of redundancy in the project selection process. These activities include internal brainstorming with subject matter experts and other stakeholders to determine the status of existing technology implementation activities and identify what major voids in capabilities exist that might be filled by pre-commercial demonstration of emerging technology solutions. PG&E's internal experts also participate in the workshops and peer reviews for other major R&D program sponsors, such as DOE, EPRI, and the National Laboratories.

The routine sharing among the EPIC Administrators of results and lessons learned from projects executed in preceding investment cycles contributes to the development of EPIC applications. EPIC Administrators also hold a number of in-person and phone-based joint portfolio review meetings to coordinate investment plans and ensure funding initiatives are complementary and not unnecessarily duplicative. These information sharing mechanisms cast the net more widely on RD&D information sources and databases than any one EPIC Administrator could do alone. PG&E goes one step further by contributing its expertise and experience to CEC workshops that help shape the CEC EPIC program content.

The project ideas that evolve from the coordinated processes of the EPIC Administrators are vetted in public stakeholder workshops. There are at least two workshops held during the writing process for an EPIC application cycle. The first workshop screens the candidate project ideas and seeks additional ideas from public stakeholders. The second workshop reviews the Research Administration Plan (RAP) for the EPIC prospective content of the application. The

34 Joint Response of Southern California Edison Company (U 338-E), Pacific Gas & Electric Company (U 39-E), and San Diego Gas and Electric Company (U 902-E) to Administrative Law Judge's Ruling Requiring Joint Applicant Responses to Questions, A.19-04-026

participants in these workshops include stakeholders in the project results as well as entities that may bid on project contractor opportunities. Participants often provide information on external activities with which the EPIC work should be coordinated. Additionally, there are often follow-up inquiries after the workshops from prospective bidders on project opportunities.

Educating Customers on Benefits of Smart Grid and Technology

PG&E sought approval for a plan to more broadly educate customers on longer-term benefits of Smart Grid technology beyond these immediate offerings, to provide context for future technologies and customer-facing benefits that will be available in the coming years. However, since the Outreach proposal in A.11-11-017 was denied, the outreach that supports the Smart Grid initiative can only be conducted through marketing of individual programs if they are approved in new cycles with outreach funds allocated. PG&E's outreach efforts over the reporting period have been focused on meeting the goals of each program.

PG&E's efforts to ensure that customers have the tools and knowledge to benefit from the Smart Grid include:

- Customer education on available tools designed to help customers understand their energy use;
- Customer education on choices for rate options and new technology that will help customers manage their energy bills; and
- Communicating with customers through communication methods they prefer, including digital self-service, email, SMS and by mail.

4.8 Smart Grid and Technology Customer Engagement by Initiative Area

In this section PG&E describes the customer engagement elements that are promoted or are available to customers for each initiative area identified in Table 4-2 above, as requested by CPUC Staff in its March 1, 2012 Smart Grid Workshop Report.

Enablement Tool: Energy Management*	
Project Description	Marketing, Education and Outreach (ME&O) to customers about interactive tools to evaluate and manage their energy use and meet their costs saving, sustainability or energy management goals.
Target Audience	Focused on Residential and SMB Customers.
Sample Message	"PG&E offers a number of ways to help you evaluate your energy use and learn how to save time, energy and money."
Source of Message	Energy Company.
Current Customer Engagement Road Block(s)	• Low engagement category. • There is a low baseline incentive for customers to be interested in incremental savings on their energy statement given the low engagement level of the utility category. • While customers are increasingly interested in digital communications, not all customers prefer communications through online channels.
Strategy to Overcome Roadblocks	• Continue to use a variety of outreach methods to ensure highest penetration possible of relevant and targeted information with residential customers. • Leverage new automation capabilities and retargeting with customers who show interest in tools or abandon during the engagement process. • Demonstrate available energy savings by highlighting customer case studies and relevant syndicated or internally developed content. • Ongoing, frequent customer communication through the Small Business and residential digital newsletters.

Enablement Tool: Behind the Meter (Customer Premises) Devices*	
Project Description	ME&O to educate customers about available home or businesses devices that: 1) Stream My Data - This is a service offered to all PG&E SmartMeter customers to connect a HAN or gateway device for RT meter data access. 2) Allow customers to participate directly in grid operations with tools like SmartAC. 3) Facilitate market adoption of EVs through increased access and availability of EV infrastructure.
Target Audience	Residential, Large and SMB customers.
Sample Message	"Save energy and money by providing RT electricity data through an energy-monitoring device."
Source of Message	Energy Company.

Current Customer Engagement Road Block(s)	• Concerns about ceding control of customer premises to utility through installed devices, such as SmartAC. • Immediate economic impact (i.e., cost savings) is not always easily seen. • Long payback periods on technology investments can make the Investment infeasible.
Strategy to Overcome Roadblocks	• Provide customers with information about devices, focusing on: o The benefits and energy management. o The potential to positively impact the customer's economic bottom line with cost savings. o Positive impact on grid stability and reliability. • Provide tools and calculators where applicable to help customers understand the choices they have. Examples include: o Solar Calculator (https://pge.wattplan.com/pv/) to review a personal estimate to understand customer specific solar savings potential o EV Calculator (https://ev.pge.com), to estimate and compare costs including savings, incentives and charger locations

Rate Options*	
Project Description	ME&O to educate customers about rate options. Includes both opt-in and default TOU rate plans for residential customers and default rates for SMB customers.
Target Audience	Residential and SMB customers.
Sample Message	"Rate options offer customers new ways to conserve energy and to choose the rate that is best for them."
Source of Message	Energy Company.
Current Customer Engagement Road Block(s)	• Lack of customer understanding about how they can benefit financially from various rate options, rates lack differentiation from a customer's perspective. • Lack of customer understanding about why TOU rates are important for the environment in a default scenario, leads to anxiety and dissatisfaction from some customers. • TOU and critical peak pricing requires action from the customer during peak hours or on event days; the utility perspective of peak hours may not align with all customer segments. • Late hours of TOU rate are significant barrier for many residential customers.

Strategy to Overcome Roadblocks	• Sustained, ongoing outreach about default rates for both Residential and SMB (prior to and after default), including context for why rates are important to the utility and environment, as well as providing information on bill protection are critical to success of default TOU. • Encourage participation in opt-in residential rates. • Provide customers examples of how to benefit from rate options on peak event days and how to prepare for an event day, including developing an action plan. • Provide education to encourage customers to shift some of their energy usage to off-peak hours. o For residential customers, a focus on educating customers on the choices and control they have over their bill by familiarizing customers with different rate options, tools, programs and tips that can help them better manage their energy use. Emphasize that small shifts in energy can make a difference on TOU rate plans. o For SMB customers, the focus will be on the changing hours of TOU. Most customers will benefit from this change, but customer have several rate options to choose from depending on their energy needs and tools to help them save.

* Not all current engagement roadblocks and strategies to overcome those roadblocks may apply to every program, tool, or service listed in the charts in 2.9

4.9 Security (Physical- and Cyber-)

PG&E initially laid out its strategy for measuring, managing and mitigating both cybersecurity technology risks and physical security risks in its June 2011 Smart Grid Deployment Plan filing. The strategy described in June 2011 highlighted PG&E's fundamental cybersecurity approach at that time. The Utility business continues to evolve. New operational models depend more and more on converged Information and Operations Technologies to perform advanced business functions such as those proposed for the Smart Grid. Many of these functions are automated and will be implemented through information-rich applications or grid automation with "smart" devices. New technologies change the risk and threat landscape. New threats continue to put pressure on and change the risk posture of the Utility requiring more protective measures and safeguards to prevent, detect, respond, and recover in a resilient manner that does not jeopardize the safe, reliable, and cost-effective delivery of energy to customers.

PG&E is in the fifth year of executing the five-year CES-21 Program in partnership with SCE, SDG&E and Lawrence Livermore National Laboratory (LLNL). CES-21 is a research effort with the primary objective of exploring the next generation of Industrial Control Systems cybersecurity and developing the foundation for Machine-to-Machine Automated Threat Response. Research programs such as CES-21 leverage IOU, academic, and/or private sector expertise can further strengthen PG&E's grid security in light of increased threats.

PG&E is positioned to address the risks presented by the evolving Utility business, including Smart Grid and technology.

Since the publication of the Smart Grid Deployment Plan, PG&E completed the Advanced Detection and Analysis of Persistent Threats (ADAPT) cybersecurity project that was primarily focused on increasing the Utility's capability to effectively anticipate, prevent, and respond to a new and emerging class of cyber and physical threats. Following the conclusion of the ADAPT project, PG&E has undertaken the implementation of a second program, the Identity and Access Management (IAM) program. This is a multi-year investment focused on improving PG&E's core access control capabilities. Discussion of PG&E's overall Cybersecurity Risk Management Program is provided in Chapter 5.

The cybersecurity projects have multiple goals and provide regulatory compliance benefits (Sarbanes-Oxley (SOX), NERC Critical Infrastructure Protection (CIP), and other standards and regulations), significant risk reduction benefits, and alignment to PG&E's Risk Management Framework (RMF) as described later in this document.

Identity and Access Management Program	**Approximate Cost Over Reporting Period:** **$7.77 Million**
Description: The IAM Program is a multi-year, multi-project enterprise level investment that strengthens authorized PG&E system access controls and reduce the risk of unauthorized access. The program improves centralized access control to key PG&E systems, provide role-based access control to those systems, centralize the authoritative source for identity attributes of authorized individuals, and provides enhanced auditing capabilities to achieve enterprise wide visibility and control of employee access to systems. Through the IAM Program, PG&E continues to implement key technologies and services in the areas of identity management, credential administration, provisioning, entitlements, access management, and audit and compliance. Funding Source: This program is funded in PG&E's 2011, 2014 and 2017 GRCs, and TO funds for the NERC CIP Program. Status: The program started in March 2012, is ongoing, and remains in progress.	

Upcoming Plans (Subject to Change): The program is currently deploying several enhancements and expansions throughout the enterprise to extend and augment existing technologies for access management. One current focus is on deployment of robotic process automation to simplify integrations of applications for regular access recertification tasks, which will allow the IAM team to provide multiple lower cost options for applications to add IAM services. This includes the ability to require training prior to provisioning of entitlements. These improvements will allow the IAM program to move integration activities from an internal project-based practice to an operations and service based practice. Future work will focus on further automation and controls to reduce the cost of ownership. Benefit Description: As of July 2019, PG&E has decreased the risk of unauthorized physical and logical access through: automated creation of network login credentials for approved and authorized users; automated removal of access from up to hundreds of separate facility access control systems for decommissioned users; centralized server access provisioning/de-provisioning, monitoring and reporting; improved governance processes for enterprise user access functions contributing to a reduction in Segregation of Duties violations by 91 percent; deployed controls to restrict and better monitor privileged accounts; deployed a centralized logical and physical access management portal called MyAccess for both physical and logical access; and retired the legacy provisioning system for SOX applications. The program continues to expand by creating controls for cross-layer segregations of duties, institute role-based access control for critical functions, integrate additional applications to the platform including key regulatory systems (e.g., SOX, NERC CIP, and Customer Energy Usage Data systems), update legacy technology to support customer authentication to externally facing PG&E applications, strengthen controls for shared administrative and service accounts, and increase efficiency and effectiveness of re-certification tasks. Benefit Category: Engaged Consumer, Smart Market, and Smart Utility – The IAM Program, enhances controls across the entire PG&E infrastructure and is not limited to the Smart Grid. Each of the Engaged Consumer, Smart Market, and Smart Utility areas benefit from these improved controls that protect key processes and systems across the enterprise. For example, the infrastructure that allows customers to log in to PG&E's My Energy will be enhanced with increased security and control mechanisms to validate that only customers and their approved designees can access customer energy information online.

California Energy Systems for the 21st Century (CES-21) Program	**Approximate Cost Over Reporting Period:** **$2.0 Million**
Description: The CES-21 Program is a public-private collaborative research and development program between PG&E, SCE, SDG&E, and LLNL. The CES-21 Program is divided into two projects which research challenges of cybersecurity and the applicability of grid flexibility metrics as the grid becomes more dynamic and complex. The CES-21 Program utilizes a team of technical experts from the Joint Utilities and LLNL, who leverage and extend ongoing research in grid modelling and cybersecurity. LLNL will combine data integration with advanced modeling, simulation, and analytical tools to provide problem solving and planning necessary for the challenges of grid integration. On April 25, 2014, the three utilities filed a joint Advice Letter (PG&E AL 4402-E) requesting approval for two research projects and the Cooperative Research and Development Agreement (CRADA), which was approved in October 2014.	

Funding Source: In D.14-03-029, which modified D.12-12-031 to comply with SB 96, the Commission authorized the three utilities to recover up to $35 million over five years for the CES-21 Program.

Status: The CPUC approved the Advice Letter (PG&E AL 4402-E) and CRADA in October 2014, allowing the IOUs and LLNL to initiate the cybersecurity and grid integration projects at the beginning of 2015. Please note that the CES-21 initiative files a comprehensive annual report. Highlights of the projects' statuses includes:

- The Cybersecurity project is in the Build/Test phase and will complete by the end of 2019. The CES-21 program represents an example of successful collaboration among the CES-21 Joint Utilities, National Labs and vendors with unique experience. 2018 was a year in which this collaboration helped to create and deliver multiple research accomplishments which will help inform the future of the grid. Previous years' modeling and simulation efforts culminated in Cycle 5, which explored the potential impacts to California's grid, as well as means of detecting and describing the malware and tactics employed in the December 2016 Ukrainian power system attack. With the installation of PG&E equipment at INL, all three IOUs now have substation instances at the Physical Test Bed. Significant progress was also made across the various sub-components of the Automated Response Research Package, including the continued development of IRL use cases and continued enhancement of vulnerability scoring capabilities. Engagement with the external stakeholder community continued throughout 2018, and the team also coordinated with and received invaluable feedback from the IOUs' Security Operations Center (SOC) representatives. As the CES-21 program enters its final year and technical work across the Cybersecurity project's task areas ramps down, an increased focus will be placed on further defining the full Machine to Machine Automated Threat Response (MMATR) roadmap and identifying capabilities on that roadmap that will not have been addressed by CES-21. Emphasis will also be placed on further engaging with the vendor community, to encourage their adoption of the capabilities developed through CES-21, for the benefit of the broader utility cybersecurity community.
- The Grid Integration Flexibility Metrics project has been completed. The results of its modeling have been socialized through the stakeholders of the Commission's Integrated Resource Planning proceeding.

Benefit Description: The CES-21 Program has the potential to deliver significant benefits to California's electric customers. Cyberattacks pose an existential threat to delivering reliable electric service to California customers. Automated response capabilities may reduce the number of outages, minimize their impact, and improve response and recovery times. The Grid Integration Flexibility Metrics project may reduce operating and capital costs and improve reliability by reducing uncertainty around appropriate metrics to gauge reliability, operating flexibility, and the adequacy of planned resources as adoption of intermittent renewables increases.

Benefit Category: Smart Markets and Smart Utility – Cross-cutting initiatives apply across all various segments.

4.10 Key Risks Overview

As part of the continuous review of its key risks, PG&E has concluded that there has been no appreciable change to those risks over the past year.

PG&E initially laid out its strategy for measuring, managing and mitigating both cybersecurity technology risks and physical security risks in its June 2011 Smart Grid Deployment Plan filing. The strategy described in June 2011 highlighted PG&E's fundamental cybersecurity approach at that time. The Utility business continues to evolve. New operational models depend more and more on converged Information and Operations Technologies to perform advanced business functions such as those proposed for the Smart Grid. Many of these functions are automated and will be implemented through information-rich applications or grid automation with "smart" devices. New technologies change the risk and threat landscape. New threats continue to put pressure on and change the risk posture of the Utility requiring more protective measures and safeguards to prevent, detect, respond, and recover in a resilient manner that does not jeopardize the safe, reliable, and cost-effective delivery of energy to customers. PG&E is positioned to address the risks presented by the evolving Utility business, including Smart Grid and technology integration.

4.10.1 Key Risks and Actions Taken to Address Them

PG&E takes a risk-based, all-hazards approach to protecting the resilience, reliability, and recovery of the computers, control systems, and other digital infrastructure that operates the electric grid. PG&E ensures executive support for cyber and physical risk management activities, and that risks are understood and managed throughout the enterprise. PG&E also maintains collaborative relationships with government, regulatory, and industry bodies to collectively protect the cybersecurity of the bulk electric power system, prioritize assets, address vulnerabilities, manage emerging risks, and maintain open lines of communication.

Since June 2011, PG&E's cybersecurity strategy has matured in numerous ways, one of which is the implementation of a new method for proactively identifying cybersecurity risk through the Risk Assessment Methodology (RAM), which complements existing efforts across the enterprise for managing risk and compliance. PG&E recognizes that focusing solely on compliance management without a holistic cybersecurity risk management approach will not achieve the desired optimal outcome to adequately protect the Utility and the Smart Grid. The RAM provides a new mechanism to identify cybersecurity risks across the enterprise. Another significant milestone is in the maturity of PG&E's overall security strategy, realized by the centralization of the security organization, which both the physical and cybersecurity groups now reside in. From a cybersecurity perspective, physical security is leveraged as part of the overall defense-in-depth strategy; a critical protection layer for the widely distributed systems and devices planned for the evolving Smart Grid.

In 2016, PG&E took several actions to strengthen the security posture of the Smart Grid, including increasing security evaluation, oversight and governance, and implementing more holistic NIST-based assessments. Moving forward, the newly implemented RAM will work in concert with PG&E's annual integrated planning process to identify new cyber risks related to the Smart Grid and plan the necessary actions to address them.

The 2016 consolidation of physical and cyber security into one organization supports an approach to system security in a holistic manner. Now that Corporate Security aligns with cybersecurity strategy, they continue to remain abreast of changes in the regulatory landscape and closely follow all Critical Cyber Assets outlined in the NERC Cyber Security Standards, CIP 006 as well as industry standards from NIST, such as those outlined in the industry guideline NISTIR 7628, Guidelines for Smart Grid Cyber Security.

4.10.2 Managing Cyber Security Risk Through Control Baseline

Controls are the system safeguards that mitigate various types of risk, and PG&E has developed a set of standardized, baseline controls that align to multiple best practice governing bodies and regulations. PG&E has established the following 17 control families as part of its baseline controls which are aligned with the NIST's Cybersecurity Controls Framework:

- Access Control
- Security Awareness and Training
- Audit and Accountability
- Security Assessment and Authorization
- Configuration Management
- Contingency Planning
- Cybersecurity Program
- Identification and Authentication

- Incident Response
- System Maintenance
- Media Protection
- Physical and Environmental Protection
- Security Planning
- Risk Assessment
- System and Services Acquisition
- System and Communications Protection
- System and Information Integrity

These control families provide a baseline for risk measurement and inform controls implementation across people, process, and technology.

4.10.3 PG&E’s Compliance with NERC Security Rules and Other Security Guidelines and Standards as Identified by NIST and Adopted by FERC

PG&E has developed and established formal standards that form the foundation for controls implementation and adherence. Examples of those standards include password management, user access management, information classification, information security, training, and privacy. PG&E’s standards leverage industry best practice standards such as NIST. PG&E also participates in industry peer groups to understand changes in technology and regularly updates applicable standards. PG&E has implemented a Guidance Document Management initiative to make standards more intuitive and easy to understand. This helps improve compliance with both the spirit and intent of the guidance.

PG&E’s RMF enables compliance with multiple state and federal regulations and is aligned to leading industry practices and standards including the following:

- NERC CIP
- Industry Guidelines
- Privacy
  - CPUC Privacy D.11-07-056
  - California SB 1476

- California SB 1386
- SCADA System Security
  - International Electro Technical Commission 62351
- Others
  - International Organization for Standardization/IEC 27000 Series
  - Federal Communication Commission Regulations
  - Sarbanes Oxley
  - Health Insurance Portability and Accountability Act

PG&E participates in multiple forums to ensure that its control design is current, comprehensive and remains in alignment with the standards and industry groups mentioned above. PG&E also engages with external partners related to cybersecurity and cyber risk management, including industry bodies, government-related security forums, and academia.

4.10.4 Key Risks Conclusions

PG&E continues to improve upon its ability to measure, manage, communicate, and mitigate potential cybersecurity, privacy, and technology risks that could impact the systems that PG&E depends on to deliver safe and reliable electric and gas services to its customers. PG&E's risk management approach is focused on ensuring that risks are well understood at all levels of the Company and that there is executive support for mitigating and managing operational risks, physical security risks as well as cyber security risk. PG&E's risk management efforts are focused on continuous improvement to effectively predict and proactively manage risk by integrating risk management strategies, plans and practices into everyday business activities.

CHAPTER 5

SMART GRID METRICS AND GOALS

5 Smart Grid Metrics and Goals

In this section, PG&E provides an update on the consensus Smart Grid metrics approved by the Commission in D.12-04-025. PG&E continues to support the Commission's position that these consensus metrics will provide parties and the Commission with information that will allow for better understanding of PG&E's Smart Grid investments and provide the foundation for moving forward with Smart Grid investments. This year, PG&E has added metrics around AMI, per CPUC request.

5.1 Customer/Advanced Metering Infrastructure Metrics

Metric 1: Number of advanced meter malfunctions where customer electric service is disrupted, and the percentage this number represents of the total of installed advanced meters. The reporting period for all Metric 1 values is July 1, 2018 – June 30, 2019.

Number of PG&E Advanced Meter Malfunctions Where Customer Electric Service is Disrupted; Percentage of Total Installed Advanced Meters	
Metric	Value
Number of Meter Malfunctions	70 meters
Percentage of Total Meters	0.0013%
Note: Reporting date: July 1, 2018 through June 30, 2019	

Metric 1a,1b, 1c, 1d:

Other Advanced Meter Malfunctions Metrics	
Metric	Value
1a. Amount of Electric Smart Meters Installed	5,437,872
1b. Amount of Electric Smart Meters Activated	5,430,321
1c. Number of Electric Opt-Out SPIDs	43,064
1d. Amount of Electric non-Smart Meters and/or amount of meters still manually read **	71,913
Notes: **Counts as of end of June 2019. **The count of meters still manually read includes Opt-Out meters.	

Metric 2: Load impact in MW of peak load reduction from the summer peak and from winter peak due to Smart Grid-enabled, utility administered DR programs (in total and by customer class).

Load Impact in MW of Peak Load Reduction From the Summer Peak and From the Winter Peak Due to Smart Grid-enabled, Utility Administered Demand Response (in total and by customer class) – Automated Demand Response Program	
Metric	Value
From the Summer Peak (May 2018 – October 2018)	
Residential*	0.99 MW
Non-Residential < 200 kW	4.25 MW
Non-Residential ≥ 200 kW	5.75 MW
Other (Agricultural)	1.5 MW
From the Winter Peak (November 2018 – April 2019)**	
Residential	0 MW
Non-Residential < 200 kW	0 MW
Non-Residential ≥ 200 kW	0 MW
Other (Agricultural)	0 MW
Note: The MW values are the average kW shed across all of the events in 2018 on a per Service Account Identification (SAID) basis and then summed. Therefore, this is not the cumulative MW load impact but the average load impact that could be expected on a per event basis. The Non-Residential <200 was determined on an SAID basis the average baseline kW for each event and if that average baseline across the events was <200 it was included in that sum. *Residential value is estimated based on the number of smart thermostat recipients multiplied by .43 kW per customer as based on the PG&E's 2016 T&D Third-Party Bring Your Own Thermostat Pilot results. **DR programs eligible for ADR are active over the timeframe of May-October.	

Metric 3: Percentage of DR enabled by AutoDR in each individual DR impact program.

Percentage of PG&E Demand Response Enabled by AutoDR in Each Individual DR Impact Program (2018)	
Metric	Value
Percentage of DR enabled by AutoDR –PDP Program	21.9%
Percentage of DR enabled by AutoDR –CBP	41.2%
Note: Percentage represents the Verified kW load reductions (engineering analysis) available for DR programs in 2018, divided by total DR portfolio kW, with the resulting number multiplied by 100. This table is not referencing cumulative load shed across the 2018 DR season.	

Metric 4: The number and percentage of utility-owned advanced meters with consumer devices with HAN or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, California Alternate Rates for Energy (CARE) status, and climate zone).

Number and Percentage of PG&E Owned Advanced Meters with Consumer Devices with HAN or Comparable Consumer Energy Monitoring or Measurement Devices Registered With PG&E		
Metric	Number	Percentage
Residential	4595	<1%
Non-Residential < 200 kW	89	<1%
Non-Residential ≥ 200 kW	5	<1%
Other	0	0%
Total	4689	<1%
CARE	0	0%
Non-CARE	4689	<1%
Total (CARE and Non-CARE)	4689	<1%
Climate Zone P	95	<1%
Climate Zone Q	49	<1%
Climate Zone R	169	<1%
Climate Zone S	465	<1%
Climate Zone T	1059	<1%
Climate Zone V	15	<1%
Climate Zone W	57	<1%
Climate Zone X	2756	<1%
Climate Zone Y	20	<1%
Climate Zone Z	4	<1%
Total by Climate Zone	4689	<1%
Note: Percentage is defined as the number of advanced meters with consumer devices with HAN or comparable consumer energy devices registered with the utility divided by the number of advanced meters installed for the group of concern, with the resulting number multiplied by 100.		

Metric 5: Number and percentage of customers that are on a time-variant or dynamic pricing tariff (by type of tariff, by customer class, by CARE, and by climate zone).

Number and Percentage of Customers on a Time-Variant or Dynamic Pricing Tariff		
Metric	Number	Percentage
Residential	678,409	14%
Non-Residential < 200 kW	536,139	79%
Non-Residential ≥ 200 kW	9,703	1%
Total	1,224,251	22%
CARE	98,460	9%
Non-CARE	1,125,791	22%
Total (CARE and Non-CARE)	1,224,251	22%
Climate Zone P	43,717	25%
Climate Zone Q	3,620	25%
Climate Zone R	155,932	26%
Climate Zone S	239,477	26%
Climate Zone T	232,507	18%
Climate Zone V	12,188	21%
Climate Zone W	75,924	25%
Climate Zone X	439,800	22%
Climate Zone Y	19,410	29%
Climate Zone Z	1,676	7%
Total by Climate Zone	1,224,251	22%
Note: Percentage is defined as the number of customers that are on a time-variant or dynamic pricing tariff divided by the number of customers in the group of concern, with the resulting number multiplied by 100.		

Metric 6: Number and percentage of escalated customer complaints related to: (1) the accuracy, functioning, or installation of advanced meters; or (2) the functioning of a utility-administered HAN with registered consumer devices.

Number and Percentage of Escalated PG&E Customer Complaints Related to (a) Accuracy, Functioning or Installation of Advanced Meters; or (b) Functioning of a PG&E-Administered HAN with Registered Consumer Devices		
Metric	Number	Percentage
Escalated customer complaints related to the accuracy, functioning or installation of advanced meters	9	27%
Escalated customer complaints related to the functioning of a PG&E-administered HAN with registered consumer devices	0	0%
Note: Percentage is defined as the number of escalated complaints related to: (1) the accuracy, functioning, or installation of advanced meters; or (2) the functioning of a utility-administered HAN with registered consumer devices. To derive percentages, the number provided is divided by the number of escalated complaints in total for each category, with the resulting number multiplied by 100.		

Metric 7: The number and percentage of advanced meters replaced before the end of their expected useful life for one year, reported annually, with an explanation for the replacement.

Number and Percentage of Advanced Meters Replaced Before the End of Their Expected Useful Life for One Year, Reported Annually, With an Explanation for the Replacement		
Metric	Number	Percentage
Advanced meters replaced	35,329	0.65%
Explanation for the replacements: These advanced electric meters were replaced due to a malfunction before the end of their expected useful life (e.g., damaged meter, etc.).		
Note: Percentage is defined as the number of advanced meters replaced before the end of their expected useful life for one year, reported annually, divided by the number of advanced meters installed, with that resulting number multiplied by 100.		

Metric 8: Number and percentage of advanced meters field tested at the request of customers pursuant to utility tariffs providing for such field tests, and the number of advanced meters tested measuring usage outside the Commission-mandated accuracy bands.

Number and Percentage of Advanced Meters Field Tested at the Request of Customers Pursuant to Utility Tariffs Providing for Such Field Tests, and the Number of Advance Meters Tested Measuring Usage Outside the Commission-Mandated Accuracy Bands		
Metric	Number	Percentage
Advanced meters field tested at the request of customers[a]	3,063	0.06%
Advanced meters tested measuring usage outside the Commission-mandated accuracy bands[b]	6	0.20%
(a) Percentage is defined as the number of advanced meters field tested divided by the number of advanced meters installed, with that resulting number multiplied by 100.		
(b) Percentage is defined as the number of advanced meters field tested found outside of the Commission-mandated accuracy bands divided by the number of advanced meters tested at the request of the customer between 7/1/18 and 6/30/19 with that resulting number multiplied by 100.		

Metric 9: Number and percentage of customers using a utility web-based portal to access energy usage information or to enroll in utility energy information programs or who have authorized the Utility to provide a third-party with energy usage data.

Number and Percentage of Customers Using a PG&E Web-based Portal to Access Energy Usage Information or to Enroll in PG&E Energy Information Programs or Who Have Authorized PG&E to Provide a Third-Party with Energy Usage Data		
Metric	Number	Percentage
Customers using a PG&E web-based portal to access energy usage information[1]	1,852,836	34%
Customers using a PG&E web-based portal to enroll in PG&E energy information programs	240,928	4.4%
Customers who have authorized PG&E to provide a third-party with energy usage data[2][3]	201,798	3.7%
(1) This number represents the unique number of customers who have accessed their usage information online within Your Account at least one time during the reporting period (July 1, 2018 through June 30, 2019). (2) Total number and percentage provided covers multiple programs. (3) This number includes Share My Data and BBP.		

5.2 Plug-In Electric Vehicle (PEV) Metric

Metric 1: Number of residential customers enrolled in time-variant EVs tariffs.

Number of PG&E Residential Customers Enrolled in a Time-Variant Electric Vehicle Tariffs	
Metric	Value
Number of EV-A Customers	58,339 customers
Number of EV2-A Customers	120 customers
Number of EV-B Customers	362 customers
Number of identified EV owners* on other time-variant tariffs	15,987 customers
Note: Utilities currently have limited ability to determine which customers have EVs, outside of enrollment in EV rate schedules, and participation in EV rebate programs. *Identified EV owners include customers that have applied for and received PG&E's Clean Fuel Rebate. Customers included in this count are on the following time-variant rates: E-6, ETOU-A, ETOU-B, or other time-variant tariffs.	

5.3 Energy Storage Metric

Metric 1: MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals as of June 30, 2019

MW and MWh of PG&E-Owned or Operated Energy Storage Interconnected at the Distribution System Level		
Metric	Location	Value
Sodium Sulfur Batteries	Vaca Dixon	2MW/14MWh
	Yerba Buena	4MW/28MWh
Lithium Ion Batteries	Brown Valley	0.5MW/2MWh
Note: A 2 MW/14 MWh battery storage system was commissioned at a PG&E substation near Vacaville in August 2012 and a 4 MW/28 MWh battery storage system on a distribution circuit in San Jose California in May 2013.		

5.4 Grid Operations Metrics

Note for reliability metrics 1 to 4: Data for all reporting periods are pulled and refreshed from the Integrated Logging and Information System (ILIS) Operations Database, which may have resulted in differences compared to prior year reported values. ILIS is used by Distribution Operators to log outage switching operations (and ancillary information about network state for System Average Interruption Duration Index (SAIDI)/Customer Average Interruption Duration Index calculations) and other relevant operations data (i.e., equipment out of service, etc.). The data used includes both unplanned and planned outages that were reported on the T&D systems. The historical Major Events determined from each annual study was used.

Metric 1: The systemwide total number of minutes per year of sustained outage per customer served as reflected by the SAIDI Major Events Included and Excluded for each year starting on July 1, 2012 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2018 through June 30, 2019.

PG&E's System Average Interruption Duration Index, Major Events Included and Excluded		
Period	Metric	Value
2018-2019	SAIDI – Major Events Included	458.4
2018-2019	SAIDI – Major Events Excluded	138.7
2017-2018	SAIDI – Major Events Included	229.8
2017-2018	SAIDI – Major Events Excluded	116.5
2016-2017	SAIDI – Major Events Included	267.7
2016-2017	SAIDI – Major Events Excluded	109.4
2015-2016	SAIDI – Major Events Included	136.4
2015-2016	SAIDI – Major Events Excluded	109.8
2014-2015	SAIDI – Major Events Included	174.1
2014-2015	SAIDI – Major Events Excluded	99.7
2013-2014	SAIDI – Major Events Included	123.8
2013-2014	SAIDI – Major Events Excluded	110.6
2012-2013	SAIDI – Major Events Included	160.9
2012-2013	SAIDI – Major Events Excluded	122.2

Metric 2: 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, 2012 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2018 through June 30, 2019.

PG&E's System Average Interruption Frequency Index Major Events Included and Excluded		
Period	Metric	Value
2018-2019	SAIFI – Major Events Included	1.505
2018-2019	SAIFI – Major Events Excluded	1.104
2017-2018	SAIFI – Major Events Included	1.141
2017-2018	SAIFI – Major Events Excluded	1.005
2016-2017	SAIFI – Major Events Included	1.462
2016-2017	SAIFI – Major Events Excluded	0.959
2015-2016	SAIFI – Major Events Included	1.132
2015-2016	SAIFI – Major Events Excluded	1.002
2014-2015	SAIFI – Major Events Included	1.155
2014-2015	SAIFI – Major Events Excluded	0.884
2013-2014	SAIFI – Major Events Included	1.090
2013-2014	SAIFI – Major Events Excluded	1.038
2012-2013	SAIFI – Major Events Included	1.211
2012-2013	SAIFI – Major Events Excluded	1.067

Metric 3: The 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, 2012 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2018 through June 30, 2019.

PG&E's Momentary Average Interruption Frequency Index Major Events Included/ Major Events Excluded		
Period	Metric	Value
2018-2019	MAIFI – Major Events Included	1.899
2018-2019	MAIFI – Major Events Excluded	1.465
2017-2018	MAIFI – Major Events Included	1.807
2017-2018	MAIFI – Major Events Excluded	1.638
2016-2017	MAIFI – Major Events Included	2.208
2016-2017	MAIFI – Major Events Excluded	1.493
2015-2016	MAIFI – Major Events Included	1.856
2015-2016	MAIFI – Major Events Excluded	1.684
2014-2015	MAIFI – Major Events Included	1.698
2014-2015	MAIFI – Major Events Excluded	1.393
2013-2014	MAIFI – Major Events Included	1.506
2013-2014	MAIFI – Major Events Excluded	1.443
2012-2013	MAIFI – Major Events Included	1.820
2012-2013	MAIFI – Major Events Excluded	1.650

Metric 4: Number and percentage of customers per year and circuits per year experiencing greater than 12 sustained outages for each year starting on July 1, 2012 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2018 through June 30, 2019.

Number and Percentage of PG&E's Customers Per Year and Circuits Per Year Experiencing Greater Than 12 Sustained Outages Per Year (Major Events excluded)			
Period	Metric	Number	Percentage
2018-2019	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,540	0.05%
2018-2019	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	30	0.97%
2017-2018	Customers Experiencing Greater Than 12 Sustained Outages Per Year	538	0.01%
2017-2018	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	13	0.42%
2016-2017	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,532	0.05%
2016-2017	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	26	0.84%
2015-2016	Customers Experiencing Greater Than 12 Sustained Outages Per Year	1,287	0.02%
2015-2016	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	17	0.55%
2014-2015	Customers Experiencing Greater Than 12 Sustained Outages Per Year	327	0.01%
2014-2015	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	6	0.20%
2013-2014	Customers Experiencing Greater Than 12 Sustained Outages Per Year	284	0.01%
2013-2014	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	6	0.20%
2012-2013	Customers Experiencing Greater Than 12 Sustained Outages Per Year	812	0.02%
2012-2013	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	15	0.49%
Note: Percentage of customers experiencing greater than 12 sustained outages per year equals [(the number of customers experiencing greater than 12 sustained outages in a year) divided by (the total number of customers)] with the resulting number multiplied by 100. Percentage of circuits experiencing greater than 12 sustained outages per year equals [(the number of circuits experiencing greater than 12 sustained outages in a year) divided by (the total number of circuits)] with the resulting number multiplied by 100.			

Metric 5: System load factor and load factor by customer class for January 1, 2018 through December 31, 2018. Load factors are calculated on a calendar year basis.

PG&E's Load Factors	
Metric	Value
System Load Factor	57.65%
Residential Load Factor	39.73%
Non-Residential < 200 kW Load Factor	Small L&P: 56.83% Medium L&P: 53.14%
Non-Residential ≥ 200 kW Load Factor	Large L&P: 69.65%
Other (Agriculture) Load Factor	45.91%
Note: Until advanced meters are fully deployed for residential, small C&I, and small agriculture customers, load factors will be calculated using estimates, rather than measured directly.	

Metric 6: Number of and total nameplate capacity of customer-owned or operated, grid-connected DG facilities. The data are cumulative through June 30, 2019.

Number and Total Nameplate Capacity of PG&E's Customer-Owned or Operated Grid Connected Distributed Generation Facilities		
Technology Category	Count	Capacity (MW)
Solar	427,348	4,097
Storage	5,706	98
Fuel Cells	279	126
Wind	273	317
Other DG	274	317
Totals	433,880	4,659

Notes:

PG&E defines DG as generation less than 20 MW in size, designed primarily to offset on-site load, that is interconnected on the customer side of the utility meter under CPUC jurisdiction (Rule 21).

D.12-04-025 defines DG as "Customer-owned or operated generating systems that are enrolled with a utility in the Self Generation Incentive Program (SGIP) or the California Solar Initiative (CSI) or otherwise operating under a Feed in Tariff (FIT)." Generation facilities receiving Feed-in Tariffs are generally not designed to offset customer load and so are not included in the Table for Metric 6.

At this time, most DG facilities interconnected in PG&E's service territory were not incentivized through the CSI or SGIP program, but rather through Net Energy Metering that provides credits for exports to the grid. Additionally, some DG is simply installed by customers on a Non-Export tariff to offset onsite load without exporting to the grid. PG&E thus believes it is more useful to present a table for Metric 6 that shows the installed count and capacity of DG by technology type rather than by incentive program as was presented in prior years. We also include storage in the table though it is not a generation technology, as it plays an important role in shaping customer load served by PG&E's grid.

The capacity for solar generating facilities is reported as the PV CEC-AC rating, while for non-solar facilities, capacity is reported as the nameplate capacity of the generation facility.

The CSI is the solar rebate Program for California consumers that are customers of the IOUs such as PG&E. This program funds solar on existing homes, existing or new commercial installations, agricultural sites as well as government and non-profit buildings.

CSI also funds a rebate program, administered by Grid Alternatives, for low-income residents that own their own single-family home and meet a variety of income and housing eligibility criteria. This program is called the Single-family Affordable Solar Homes Program. Additionally, PG&E administers a CSI-funded solar rebate Program for multifamily affordable housing. This program is called the Multifamily Affordable Solar Housing Program.

The SGIP provides incentives for storage and generation technologies installed behind the meter to offset all or a portion of on-site load. SGIP's goals include grid support, GHG reduction and market transformation.

Metric 7: Total electricity deliveries from customer-owned or operated, grid-connected DG facilities, reported by month and by ISO sub-Load Aggregation Point. This information is for July 1, 2018 through June 30, 2019.

Year	Month	Approximate Exports*(GWh)
2018	Jul	328.3
2018	Aug	309.6
2018	Sept	286.3
2018	Oct	257.4
2018	Nov	156.1
2018	Dec	144.2
2019	Jan	160.7
2019	Feb	197.4
2019	Mar	324.2
2019	Apr	389.8
2019	May	429.2
2019	Jun	450.8
Note: Information and estimates about production of DG facilities that serve on-site customer load is produced annually by the CEC in their California Energy Demand Forecast. *Exports listed are approximate and subject to slight variation due to changes to PG&E's internal database structures and rounding.		

Metric 8: Number and percentage of distribution circuits equipped with automation or remote-control equipment, including SCADA systems. The measure is for July 1, 2018 through June 30, 2019.

Number and Percentage of PG&E's Distribution Circuits Equipped with Automation or Remote-Control Equipment, Including SCADA			
Metric	# of Automated Circuits	Total Circuits	Percentage
PG&E Distribution Circuits Equipped with SCADA at the Breaker	3,070	3,165	96.9%
Note: Percentage of distribution circuits equipped with automation or remote-control equipment equals the number of distribution circuits equipped with automation or remote-control equipment) divided by the total number of distribution circuits with the resulting number multiplied by 100.			

CHAPTER 6

APPENDIX I

6 Appendix I

2018/2019 Smart Grid Annual Report

Approximate Recorded Smart Grid Project Costs from July 1, 2018 Through June 30, 2019[35]

Project Name	7/1/18 to 6/30/19 Approximate Recorded Amount
Community Wildfire Safety Program	
PGE.com Portal Enhancements	$0.3 Million
DMS/OMT/ILIS Enhancements	$9 Thousand
Enhanced Asset Inspections – Drone/AI	$5.33 Million
Weather Station Deployment / Hi-Def Camera Deployment	$6.4 Million
Wildfire Analysis & Response	$2 Million
POMMS Enhanced Fire-Risk Modelling	$1 Million
Resilience Zones	$2 Million
Accelerated Vegetation Management – IT Field Tool	$2.4 Million
Customer Engagement and Empowerment Projects	
Supply Side (SSP) / SSP II DR Pilot (Continuation of Intermittent Resource Management Pilot Phase 2)	$0.94 Million
XSP	$0.54 Million
AC Cycling Next Generation Technology Assessment	$5.03 Million
EV Rates	$0.1 Million
EV Infrastructure	$44.36 Million
Energy Diagnostics and Management	$3.96 Million
BFA	$0.024 Million
Share My Data (CDA) Project	$2.8 Million
Energy Data Access	$0.3 Million
Stream My Data aka Home and Business Area Network (HAN)	$0.2 Million
BBP	$0.21 Million
TVP Rates	$7.2 Million
AutoDR Program	$2.5 Million
Smart Thermostat Study	$0.055 Million
Distribution Automation and Reliability Projects	
ADMS	$7.34 Million
Distribution Substation SCADA Program	$39.6 Million

35 For information on project costs in former years, please reference past Smart Grid Deployment Plan Updates on CPUC's California Smart Grid website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

Project Name	7/1/18 to 6/30/19 Approximate Recorded Amount
Smart Grid Fault Location, Isolation, and Service Restoration (FLISR)	$8.03 Million
Transmission Automation and Reliability Projects	
Transmission Substation SCADA Program	$9.2 Million
MPAC Installation Program	$59.2 Million
Synchrophasor Project Realization	$0.5 Million
EMS	$4.5 Million
Asset Management and Operational Efficiency Projects	
Network SCADA Monitoring Project	2019 $9.3 Million / 2019 $7.7 Million
Wind Loading Assessments	$0.8 Million
STAR for Transmission Line	$1.96 Million
STAR for Electric Distribution Hardening	$1.43 Million
Security (Physical and Cyber) Projects	
IAM Project	$7.77 Million
Integrated and Cross-cutting Systems Projects	
Telecommunications Architecture	$1.035 Million
CES-21 Program	$2 Million
EPIC Program	$10.2 Million

Project Name (Closed)	Completion Date
Customer Engagement and Empowerment Projects	
Intermittent Renewable Resource Management (IRRM) Pilot Phase 1 In the IRRM Pilot Phase 1, PG&E leveraged work performed under the C&I DR Participating Load Pilot to provide regulation services to the CAISO. The objective of the IRRM Pilot Phase 1 was to demonstrate whether customers can provide second by second frequency-regulation service needs to the CAISO.	2011
Plug-In Hybrid Electric Vehicle (PHEV)/EV Smart Charging Pilot In the PHEV/EV Smart Charging Pilot, PG&E and the EPRI tested baseline functionalities of PEV charging hardware by conducting an end-to-end system connectivity to evaluate potential residential smart charging capabilities utilizing the load management software over the SmartMeter network.	December 2011
UAT PG&E provides the Home Energy Checkup and Business Energy Checkup (also known as UATs) for residential and SMB customers through My Energy. These tools utilize SmartMeter data along with other customer insights to make it easy for our customers to find energy savings ideas that are particular to how they use energy. The tools are progressive in nature, continually learning based on the information the customer provides, and include recommendations across EE, DR, DG, and behavioral changes.	September 2012
The Green Button Initiative In PG&E's Green Button Initiative, the Green Button tool provides customers with a means of easily accessing and downloading their energy use online in a standardized format that can be shared with energy service providers.	October 2012
My Energy Web Tools PG&E's customer website – My Energy – allows residential, SMB, and small agricultural customers to view usage, price and cost, and take advantage of various rate analysis tools. The usage information is displayed in a variety of formats including year-to-year comparison, peak/ off-peak, hourly and 15-minute interval data (depending on the granularity of the SmartMeter data), bill to date and monthly bill forecast. The "My Energy" website will also include a rate calculator which will calculate the customer bill under a variety of available rate plans.	November 2012
PDR Program Phase 1 As part of the Commission's vision of integrating retail-wholesale DR programs, in the PDR Program Phase 1, PG&E is in the process of enabling its retail DR programs to directly participate in the CAISO's wholesale market – PDR product. Phase 1 of this project was focused on assembling the proper tools (i.e., telemetry, forecasting) and integrating interfaces (procurement back-end systems to schedule, notify and settle) that PG&E needs to operate when bidding available DR resources in the CAISO market.	2013
Energy and Carbon Management System (ECMS) In the ECMS, PG&E has developed tools specifically for PG&E's large C&I customer account representatives to identify opportunity customers and enable a consultative energy discussion with those customers using advanced usage analytics and financial metrics for proposed EE projects.	December 2013

Project Name (Closed)	Completion Date
SmartMeter Program PG&E's SmartMeter Program launched the deployment of foundational technology to help PG&E's customers understand how and when they use energy, including through automated home energy management. The SmartMeter system improved infrastructure integrity, helped PG&E manage energy demand, and enabled PG&E to provide more reliable service. Through these broad systemwide enhancements, the SmartMeter Program has served the vital foundational step to enable creation of the Smart Grid, which in turn fosters a clean energy economy and sustainable economic expansion.	December 2013
HAN Enablement Program – Phase 1 & Phase 2 PG&E's HAN Enablement Program is an infrastructure that allows customers to register and commission a standards compliant device with PG&E's AMI network to receive near RT data from their SmartMeter. In HAN Phase 1 (Initial Deployment), which ran from March 1, 2012 through April 30, 2013, PG&E installed and supported 430 in-home displays with residential customers. Starting in January 2013, PG&E launched HAN as a platform, making the capability to register a device and received near real time usage information from a customer's electric SmartMeter available to all eligible customers across its service territory.	April 2013 and February 2014
Opower/Honeywell Smart Thermostat Assessment Pilot PG&E conducted a Smart Thermostat field assessment with Opower and Honeywell to evaluate the energy benefits that accrue to customers who utilize internet-enabled thermostats, when exposed to behavioral energy saving messaging. This effort was a component of the EE Portfolio's Emerging Technologies Program. PG&E successfully installed Honeywell Smart Thermostats in 505 residential homes in the San Francisco Bay Area and the Central Valley in February 2013. Opower and PG&E monitored usage differences between the test and control groups for a 12-month period.	July 2014
Opower/Honeywell Smart Thermostat Assessment Pilot PG&E conducted a Smart Thermostat field assessment with Opower and Honeywell to evaluate the energy benefits that accrue to customers who utilize internet-enabled thermostats, when exposed to behavioral energy saving messaging. This effort was a component of the EE Portfolio's Emerging Technologies Program. PG&E successfully installed Honeywell Smart Thermostats in 505 residential homes in the San Francisco Bay Area and the Central Valley in February 2013. Opower and PG&E monitored usage differences between the test and control groups for a 12-month period.	July 2014
Green Button Connect (GBC) Beta GBC is a software interface that allows PG&E customers to easily share their SmartMeter enabled energy usage data with other energy service providers. These developers can then "mash up" the data in unique ways to provide valuable insights to customers. GBC was retired when PG&E launched its Share My Data platform.	March 2015
Demand Response Transmission and Distribution System Integration In T&D 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. The first phase included a study of the required DR resource characteristics to meet distribution needs. The pilot conducted field demonstration projects as part of 2015-2016 DR Bridge Funding Activities (D.14-05-025). Demonstration projects included the deployment of local DR resource zones that can be called by Distribution Operations to maintain local system reliability, development of behavioral DR resources that can be locally called by Distribution Operations and testing the feasibility of automated calling of DR resources linked to SCADA.	April 2017

Project Name (Closed)	Completion Date
DR PEV Pilot The DR PEV Pilot demonstrated the technical feasibility as well as the value of managed charging of EVs as a flexible and controllable grid resource. The main goal of this project was to understand the potential of using EVs for grid services, which can result in cost savings associated with operating and maintaining the grid as well as owning and operating a vehicle. The pilot required Bavarian Motor Works (BMW) to provide a minimum of 100 kW of capacity at any given time, regardless of how many BMW i3 EVs are charging. Once an event is called, BMW utilized proprietary aggregation software to delay charging of participating customers (via telematics embedded in the vehicle) to reduce load on the grid. The algorithm prioritized the reduction of electricity consumption from charging without interfering on customers' mobility needs; however, drivers can opt-out of event participation at any time. To address uncontrollable fluctuations regarding managed charging capacity, BMW developed a stationary battery system made up of eight used MINI E batteries (100 kW/225 kWh) as back-up storage to fill the gap between available load drop from managed charging and the required DR capacity.	December 2016

Project Name (Closed)	Completion Date
Distribution Automation and Reliability Projects	
Cornerstone Improvement Project – Feeder Automation The Cornerstone Improvement Project includes the installation of distribution feeder FLISR systems on select urban and suburban circuits. The project is expected to result in reliability improvements for PG&E customers. The Feeder Automation component of Cornerstone Improvement Project involves implementing feeder automation on approximately 400 distribution circuits. The project scope includes automating mainline protection equipment utilizing FLISR schemes to restore unaffected customers within five minutes.	December 2013
Regional Synchrophasor Investment Project As part of this project, PG&E installed or upgraded Synchrophasor technology, also known as PMUs, throughout its service territory, has networked them together, and provided the data in a secured interface to PG&E's electric transmission operators, Western Electricity Coordinating Council (WECC), neighboring utilities, and the CAISO. The data exchange portion of the project includes positioning PG&E to share data with WECC. Nine other partner entities can coordinate and exchange data amongst partner entities, including PG&E.	May 2014
SmartMeter Outage Management Integration Project The SmartMeter Outage Management Integration project integrates the SmartMeter "Last Gasp" and Restoration messages into PG&E's OMS for outage notification to operators and dispatchers and improved outage restoration. Phase I project delivered: (1) the capability to create trouble reports from AMI alarms when an associated customer call has been received; (2) the capability to ping a transformer to determine if an outage is larger than it was inferred to be; and (3) the capability to ping individual meters to determine whether they have been restored. Phase 2 of the project delivered functionality to identify and isolate downstream outages that have occurred prior to a larger upstream outage. Additionally, it will enhance the capability introduced in Phase 1 by removing the requirement for an associated customer call and automatically creating trouble reports using AMI only reports.	November 2015
EPIC 1.01: Energy Storage for Market Operations EPIC 1.01 Energy Storage for Market Operations project successfully utilized PG&E's Vaca-Dixon and Yerba Buena BESSs to gain experience and data by participating in CAISO's NGR market model. PG&E developed and deployed an automated communications and control solution to fully utilize and evaluate BESS fast-response functionalities.	September 2016
Install Smart Grid Line Sensors Pilot The objective of the project was to pilot how line sensors can: (1) provide more accurate information about the fault location area, allow faster outage restoration by reducing outage response time, and improve customer satisfaction; (2) provide accurate current flow information to operators and engineers to plan and reconfigure the system without overloading equipment	December 2016

Project Name (Closed)	Completion Date
based on actual current measurements instead of models; and (3) provide more accurate current flow information to engineers to support better planning of the distribution system rather than relying exclusively on models.	
Voltage and Reactive Power (Volt/Var) Optimization System Pilot This project piloted a voltage and reactive power (Volt/Var) optimization technology to evaluate the technology's ability to reduce customer energy usage and reduce utility system losses by managing the distribution voltage from the substation to the customer's service point (distribution primary, secondary and service systems). Volt-Var Optimization (VVO) is a software based solution that analyzes grid conditions, determines the device-level adjustments necessary to regulate voltage, and communicates coordinated commands to grid devices in real time. VVO control systems act as a centralized voltage and reactive power control "brain" of the electric distribution system, for evaluating and signaling the actions needed for better voltage and reactive power regulation.	December 2016
Detect and Locate Faulted Circuit Conditions Pilot This project installed and evaluated a fault-finding software system and systems that assist in more precisely locating failed equipment that caused an outage and determined if there are additional benefits of providing a more accurate location to utility first responders to outages.	December 2016
Transmission Automation and Reliability Projects	
Compressed Air Energy Storage (CAES) Demonstration Project The purpose of this demonstration project was to determine the technical and economic feasibility of an approximately 300 MW CAES plant using a porous rock structure for up to 10 hours of air storage at a location within California. CAES technology consists of compressing air into an underground porous rock formation during periods of excess generation and then releasing the stored air to generate electricity during periods of peak demand.	2017
Asset Management and Operational Efficiency Projects	
Transformer Load Management Project The SmartMeter Transformer Loading Management project enables T&D electric planning engineers and estimators to access actual customer usage data from SmartMeter for analysis in equipment sizing and voltage analysis. The solution will enable PG&E to report transformer (or multiple transformers) load based on interval usage data and the ability to drill down to month, week, day, and Service Point level to see the peak usage. The solution will also identify transformer (or multiple transformers) by load category (over loaded, under loaded) over the entire SmartMeter population.	June 2012
Load Forecasting Automation Program The Load Forecasting Automation Program will automate existing manual electric distribution system load forecasting to increase accuracy of the process and improve forecast documentation. Current and future SCADA data will be gathered and stored within the existing data historian system and will become an input to the new forecasting tool. Circuits with SCADA will provide hourly load data into the historian system and non-SCADA circuits will provide a single monthly peak load from monthly substation inspections. Additionally, this project will replace analog bank demand meters with electronic recording meters.	October 2012
CBM – Substation Project The CBM Substation Project was a PG&E initiative to convert substation inspections collected on paper to a centralized electronic form. Centralizing the data aids in identifying problematic substation assets based on inspected condition trends in a predictive manner. The CBM technology solution for substation provides the platform for equipment inspection readings, temperature, and other data points to provide equipment predictive maintenance. The solution will automate many of the manual processes that are used today including: (1) review of station inspection and test data to identify abnormal conditions; (2) update maintenance trigger plans from oil condition assessment results, counter readings, etc.; and (3) equipment ranking for replacement decisions. The tool is also designed to provide easy access to inspection and test data to asset strategy and engineering personnel that do not have it readily available today. The data will be used to adjust maintenance triggers and for capital investment strategy.	February 2013

Project Name (Closed)	Completion Date
Electric Distribution Geographic Information System and Asset Management (Electric Distribution GIS/AM) Project The Electric Distribution GIS/AM project is a continuation of and enhanced approach to the Automated Mapping and Facilities Management (AM/FM) Project, where PG&E upgraded hardware and software components from 2008 2010 and completed alignment of electric and gas maps to a common coordinate scheme or "land base," to prepare the maps for migration and conversion into a new enterprise GIS solution. While the purpose and scope of the Electric Distribution GIS/AM project is consistent with and leverages work completed as part of the predecessor AM/FM project, key enhancements are being made to drive increased business value with the integrated GIS and enterprise AM system (SAP) data. A significantly more rigorous approach to assure data quality and implement data governance processes is included as part of the new Electric Distribution GIS/AM project. In addition, the scope of the Electric Distribution GIS/AM project has been expanded to include web based analytics for multiple Electric Distribution functions. These and other capabilities are more fully detailed and scoped in the GIS/AM project as compared to the 2011 GRC AM/FM forecast, resulting in a more comprehensive and longer duration project.	December 2015
Security (Physical and Cyber) Projects	
Advanced Detection and Analysis of Persistent Threats (ADAPT) Cyber Security Project The ADAPT project is focused on increasing PG&E's ability to effectively anticipate, prevent, and respond to current and shifting cyber and physical threats by enhancing the following three control areas: a) Intelligence and threat management controls: Build specific "early-warning" controls that electronically collect, analyze, and correlate information on Utility targeting threats before they "approach" the Utility's logical perimeter. b) Advanced detective and preventative controls: Develop controls that "harden" the Utility's cyber security infrastructure with multiple layers of technology to filter, quarantine, and send alarms on questionable data. c) Adaptive response controls: Enhance incident monitoring, response, and investigation capabilities to quickly respond to potential security incidents.	May 2012
Integrated and Cross-Cutting Systems Projects	
SmartMeter™ Operations Center (SMOC) The SMOC project implements telecommunication network operations management capabilities to support PG&E's SmartMeter network to handle growth in the number of deployed meters, effectively monitor the increased amount of data communications from the meters, bring new SmartMeter‐related customer services on-line efficiently, and enable timely customer response as well as proactive reliability and availability management. This scope includes designing and implementing a new SMOC for the day to day operations of the existing installed systems and ensure vendor production and operational commitments.	July 2012
Applied Technology Services (ATS) Distribution Test Yard (DTY) The DTY will serve as an electrical laboratory that includes simulated distribution capabilities for monitoring and evaluating various new distribution tools, equipment, and applications. It will include the necessary primary line equipment with isolated communications networks to allow safe and thorough testing without risking network security issues. This DTY is part of the overall ATS end to end test capability for distribution systems of the future.	September 2012

Project Name (Closed)	Completion Date
Data Historian Foundation Project This project will implement enhanced data historian software for managing and analyzing operational data with select user groups in electric transmission, gas operations, power generation, and energy procurement. When deployed and integrated with other electric systems such as EMS and SCADA, the new data historian will serve as the central data archiving and analysis system for all-time series operational data. This solution enables PG&E operators, engineers, managers and executives to analyze, visualize, and share operational and business data in a manner that not only makes the most sense to them, but also informs intelligent decision-making throughout the utility value chain. The benefits of this capability include productivity improvements, situational awareness, reliability improvements, and regulatory compliance. A separate project is required to enable these capabilities for electric distribution.	July 2014
Information Management Architecture PG&E proposed to invest in a core set of Information Management and processing capabilities to allow participants in the Smart Grid to have timely access to the best available data to drive their energy related decisions. The Information Architecture foundation includes enhanced decision support tools to more accurately analyze, predict, and respond to energy impacting events based on data processed from a multitude of systems and stakeholders. The approach to information management is being optimized and will launch as a new project in 2017.	January 2016
EPIC 2.22-Demand Reduction - Analytics This project used load, interval and other sources of data to develop a new analytical tool to identify strategic customers and target demand reduction in local areas by combining and integrating multiple DSM technologies (e.g., EE, DR, DER, Consumer-oriented Energy Tools). The project investigated whether PG&E can achieve a sufficient amount of demand reduction, give visibility into the customer-side resources and improve the reliability of customer-side resources at the local level in order to delay the need for local capacity expansion expenditures. Main project phases: 1) Screening tool 2) TDSM dashboard 2.0, capturing algorithm insight for 3rd parties, and 3) Tracking/monitoring.	February 2018
EPIC 2.14-Phase ID This project successfully developed and demonstrated automated analytical methods for determining meter phasing and meter-to-transformer connectivity using SmartMeter™, SCADA and GIS data.	July 2018
EPIC 2.07 - Real Time Loading Data for Distribution Operations and Planning This project developed analytical methods for generating near RT load forecast information. The project successfully built and demonstrated a platform to ingest and process SmartMeter™, SCADA, PV system generation, GIS and weather data for two of the eight Areas of Responsibility (AOR) within PG&E's service territory.	November 2018
EPIC 2.14 - Automatically Map Phasing Information This project successfully developed and demonstrated automated analytical methods for determining meter phasing and meter-to-transformer connectivity using SmartMeter™, SCADA and GIS data. The distribution network model is central to multiple existing control systems, system analyses, and work processes. As the load characteristics of the distribution network evolve, such as with the growth of DER, it is becoming more important to have accurate and up-to-date network model information to be able to actively manage the distribution system. Automated approaches for obtaining this information can offer a more efficient alternative to the conventional boots-on-the-ground approach.	December 2018
EPIC 2.02- DERMS This project provided an opportunity for PG&E to define and deploy a DERMS and supporting technology to uncover barriers and specify requirements to prepare for the increasing challenges and opportunities of DERs at scale. The DERMS Demo was a ground-breaking field demonstration of optimal control of a portfolio of 3rd party aggregated behind-the-meter (BTM) solar and energy storage and utility front-of-the-meter (FTM) energy storage to provide distribution capacity and voltage support services while also allowing for participation of these same DERs in the CAISO wholesale market.	December 2018

Project Name (Closed)	Completion Date
EPIC 2.03A SIs This project conducted field demonstration of commercial SIs on a high PV-penetration distribution feeder ("Location 2"), the evaluation of a vendor-agnostic SI aggregation platform, and lab testing of multiple SI models. The project established that there is significant potential for local voltage support from SIs to help mitigate local secondary voltage challenges caused by high PV penetration in a cost-effective manner. Efforts undertaken within the project were not able to establish that individual or aggregations of SIs were able to substantially affect primary voltage.	February 2019
EPIC 2.05 - Inertia Response Emulation for DG Impact Improvement This project explored the capabilities of inverter-based energy resources to provide a set of functions related to system inertia which support the electric system. The project demonstrated via transmission system modeling and Power-Hardware-In-Loop testing that advanced inverter control methods can provide active power support that improves the system's frequency response in the face of reduced conventional inertia from synchronous machine generators. Inverter control methods were explored including inertia-like response (derivative control) and grid-forming (voltage source) modes for respective benefits in bulk system and isolated distribution system use cases.	February 2019