PACIFIC GAS AND ELECTRIC COMPANY

2022 WILDFIRE MITIGATION PLAN UPDATE

SECTION 7.1.E

ATTACHMENT 1

PACIFIC GAS AND ELECTRIC COMPANY
2022 WILDFIRE MITIGATION PLAN
SECTION 7.1.E, ATTACHMENT 1

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7.1.E, Attachment 1

7.1.E.(3) New or Emerging Technologies – Project Details (Continued)

The detailed project information for Section 7.1.E New or Emerging Technologies is provided in the following standardized format indicated in Table PG&E-7.1.E-2 below. PG&E's reporting format is based upon improvements resulting from Energy Safety feedback, as well as an additional requirement in 2021 that PG&E provide improved quantitative performance metrics and quantitative risk reduction benefits for the portfolio. In this 2022 WMP Update, PG&E is now also providing estimated Risk Spend Efficiency (RSE) scores for each of the projects, as applicable.

TABLE PG&E-7.1.E-2:
STANDARDIZED FORMAT FOR NEW AND EMERGING TECHNOLOGY REPORTING

<table>
<tr><th>Information Type</th><th colspan="2">Description</th></tr>
<tr><td>(i).A: Project Type</td><td colspan="2">Either New Technology (Commercially Available Offering) or Emerging (Pre- commercial) Technology according to the definition provided in Section 7.1.E(1).</td></tr>
<tr><td>(i).B: Project Objective and Summary</td><td colspan="2">A summary of the project, including its wildfire mitigation-related objective and an indication of whether the project is progressing toward broader adoption, if known. For many new or emerging technology projects, it is not clear until late in the project lifecycle whether the results indicate that the technology is appropriate to be broadly adopted.</td></tr>
<tr><td>(i).C: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted</td><td colspan="2">PG&E is providing one or more UWMMM Categories and Capabilities potentially impacted, where anticipated. Due to the nature of new and emerging technology project developments, these potential Categories and Capabilities are subject to change.</td></tr>
<tr><td rowspan="5">(ii).A: Project Phase</td><td colspan="2">The project phase is reported according to the following definitions:</td></tr>
<tr><td>Project Phase</td><td>Definition</td></tr>
<tr><td>Initiation</td><td>Project purpose and benefits defined
Initial scope, schedule, budget
Sponsor, stakeholders, project team defined</td></tr>
<tr><td>Planning</td><td>Business case including refined scope, schedule, budget and approvals
Benchmarking for non-duplication, lessons learned, and industry best practices</td></tr>
<tr><td>Design/ Engineering</td><td>Detailed design, technical requirements, coordination
Contracting</td></tr>
</table>

TABLE PG&E-7.1.E-2:
STANDARDIZED FORMAT FOR NEW AND EMERGING TECHNOLOGY REPORTING
(CONTINUED)

Information Type	Description	
	Staging	Review and confirmation of project alignment with purpose, benefits, scope, budget, schedule Key success factors defined
	Build/Test	Build, test, and demonstration Evaluation to defined metrics
	Closeout	Path to production revised Lessons learned documented Decommissioning completed Final report
	Continuous Improvement	Optional phase that some projects progress to when there is project-related continuous improvement activity post Closeout.

**TABLE PG&E-7.1.E-2:
STANDARDIZED FORMAT FOR NEW AND EMERGING TECHNOLOGY REPORTING
(CONTINUED)**

Information Type	Description
(ii).B: Project Status	A summary of the current state of the project, with activity indicative of whether the project is progressing toward broader adoption. For many new or emerging technology projects, it is not clear until late in the project lifecycle whether the results indicate that the technology is appropriate to be broadly adopted.
(ii).C: Project Location	For field-based projects the general location is provided. For software or analytics-only projects, the area the project applies to is provided, such as to High Fire Threat Districts (HFTD) or systemwide.
(iii).A: Results to Date	Results of pilot projects are provided through the end of October 2021. Project results for prior quarters are included, either labeled by quarter or as Prior Results that may extend to the origin of the project. Results for pilot projects in phases preceding the Closeout phase, as defined in (ii).A, are preliminary and subject to change.
(iii).B: Lessons Learned	Lessons learned for pilot projects are technological learnings, findings, and key takeaways to inform a path to production. Lessons learned can also be barriers, issues, risk, or obstacles that if not solved could jeopardize the path to production. Lessons learned provided for projects in phases preceding the Closeout phase, as defined in (ii).A, are preliminary and subject to change.
(iii).C: Quantitative Performance Metrics	Quantitative performance metrics, along with preliminary corresponding performance targets, are provided for the projects in this portfolio, where appropriate. In subsequent quarterly and annual updates, and as these projects progress, Pacific Gas and Electric Company (PG&E) will refine these quantitative performance metrics, the performance targets associated with these metrics, and identify performance against these metrics as they become available. In addition, several of the projects in this portfolio, including but not limited to foundational projects, are evaluated on a delivered feature set or pass/fail basis. In such cases, non-quantitative or minimum deliverable criteria are provided and identified as such. Performance measures are provided for the evaluation of the effectiveness of the technology during the project specifically, and do not extend beyond to any eventual uses of the technology if subsequently deployed.

TABLE PG&E-7.1.E-2:
STANDARDIZED FORMAT FOR NEW AND EMERGING TECHNOLOGY REPORTING (CONTINUED)

Information Type	Description
(iii).D: Quantitative Risk Reduction Benefits	The Enterprise Risk Model is used to calculate quantitative risk reduction benefits that may result from adoption and deployment of the technologies being demonstrated or piloted in this section. The estimated risk reduction considers the total potential risk reduction impact from ten years of the deployment of the technology (e.g., system-wide, Tier 2 and 3 HFTD, specific types of distribution circuits, or a certain number of line-miles) depending on the specific assets or geographic scope where the technology is applicable, and independently of any other risk reduction projects. For each project below, as applicable, an estimated potential risk reduction score, Risk Spend Efficiency Score (RSE), and summary of the underlying assumptions are provided. The scores provided are estimates assuming ten years of deployment of the technology as defined, with operations and maintenance costs over those ten years included, and with the benefit life capped at ten years as well even though some of the technologies may have a benefit life of a longer duration. The intent of calculating these scores in this section in this way is to provide a potentially more levelized way to evaluate the cost benefit potential of these emerging technologies amongst themselves, noting that these scores are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3. There is inherent uncertainty in the assumptions and estimates that are developed to create these quantitative risk reduction benefits. Risk reduction benefits for a particular project should be viewed as initial potential estimates if the technology is proven to meet current estimates and will be refined in subsequent updates, as assumptions around the types of assets impacted, the applicable scope of deployment, the costs, and the effectiveness of the technology are refined. Projects classified as foundational do not lend themselves to the calculation of quantitative risk reduction benefits. Instead, these projects enable other technology projects to build on foundations to potentially provide quantitative risk reduction benefits. In these foundational project cases, there is an explanation of either specific projects that are built upon the foundation that may provide quantitative risk reduction benefits or a general qualitative explanation of risk reduction benefits that may be provided in the future.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the project, in any phase, identifies a potential ignition or fault risk condition (e.g., an in-field asset condition or configuration issue, or a vegetation issue), the potential condition is reported and validated against current PG&E preventive and corrective maintenance guidelines and treated in accordance. In addition, a general statement of such activity is provided in this response.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Typically, methods to incorporate ignition or fault risk mitigation findings into operational practices are revealed toward the end of the projects as part of the lessons learned and other recommendations in the Closeout documentation. However, if PG&E identifies such risk mitigation methods to inform proposed changes to operational practices, including prior to the conclusion of the project, they will be included in this response.

TABLE PG&E-7.1.E-2:
STANDARDIZED FORMAT FOR NEW AND EMERGING TECHNOLOGY REPORTING
(CONTINUED)

Information Type	Description
(v).A: 'End Product' at 'Full Deployment' and Location	For this response PG&E is providing the anticipated use of the technology, including anticipated locations, should the technology be proven to be successful and subsequently put into production. Given that the projects are in varying phases of development and precommercial technologies are inherently uncertain, this response is based upon our current understanding of the technology and its applicability to PG&E operations, and subject to change. Early-stage projects may not have a clear strategy for the 'end product' at 'full deployment', while others such as those in the Continuous Improvement phase may have already been deployed.

Forward-looking statements detailed throughout this section, including but not limited to project next steps, expected results, potential quantitative risk reduction benefits, and RSE scores, are subject to change due to the evolving nature of technology and drivers of system and public safety risk. In the remainder of this section, the projects described below are organized by Program Areas as described in Section 7.1.E.

<u>Program Area</u>: Situational Awareness and Forecasting – New or Emerging Technologies

PG&E is deploying a set of complementary tools to better assess and more accurately locate, often in near real time, environmental events and grid conditions 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. Below are potential mitigations leveraging new or emerging technologies; for additional information reference Section 7.3.2.

TABLE:
SmartMeter™ PARTIAL VOLTAGE DETECTION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	PG&E's EPIC 1.14: Next Generation SmartMeter Telecom Network Functionalities project demonstrated that the SmartMeter Telecommunications Network can support a variety of both present and future smart grid applications and devices, including using multiple types of outage reporting data from the SmartMeter network to better identify and differentiate wire down type outages and share information with distribution management systems (DMS) more effectively. The SmartMeter Partial Voltage Detection (formerly known as Enhanced Wires Down Detection) project builds on this work to assess the ability to use SmartMeter technology to locate and identify partial voltage conditions to enable faster response to grid issues. A partial voltage condition can indicate the occurrence of a potentially hazardous distribution grid condition, including hazards that can contribute to wildfire risk. PG&E has enabled Single-Phase SmartMeters to send real-time alarms to the DMS under partial voltage conditions (25-75 percent of nominal voltage). Prior to implementation, SmartMeters electric meters could only provide real-time alarms for the outage state. For Three-Wire distribution systems, the partial voltage condition indicates one phase feeding the transformer has low voltage or no voltage. This enhanced situational awareness can help detect and locate the area boundaries between meters encountering normal voltage and those encountering partial voltage. This allows operators to detect and locate partial voltage line sections more quickly to enable faster response to potential wires down, open jumpers, or loss of phase(s) due to unganged fuse operation. Partial voltage detection technology has proven successful on 3-Wire distribution systems where transformers are connected line-to-line, and loss of phase results in a partial voltage condition whereby the communication card can detect and then send alerts to the DMS during the event. Referred to as Phase 1, this portion of the project completed in 2019 and included implementation on 4.5 million single phase SmartMeter electric meters covering 25,597 line miles of Tier 2 and Tier 3 HFTD areas. Phase 2 of this project was completed in June 2021, applied to ~411,000 (originally ~365K) 3-phase SmartMeter electric meters, and relied upon the implementation of firmware detection of partial voltage conditions. The Phase 2 technology alerts on partial voltage conditions on 4-Wire systems where transformers are connected line-to-neutral.

TABLE:
SMARTMETER PARTIAL VOLTAGE DETECTION
(CONTINUED)

(i).C: UWMMM Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Phase 1: Closeout (~4.5M single-phase meters have been in production since 2019). Phase 2: Closeout (~411K three-phase meters were put into production status in June 2021).
(ii).B: Project Status	Phase 1 is in production and has been deployed to ~4.5M meters system-wide. Phase 2 is in production and has been deployed to ~411K meters system-wide.
(ii).C: Project Location	Phase 1: Tier 2 & 3 HFTDs were initially targeted; now deployed system-wide. Phase 2: Tier 2 & 3 HFTDs were initially targeted; now deployed system-wide.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Phase 2 Project Results: The deployment was completed in June 2021 and is now in production. Q2 2021 Phase 2 Project Results: Completed deployment in June and is in production. Q1 2021 Phase 2 Project Results: SmartMeter firmware general release received from vendor. Regression testing started. PG&E was awarded United States (U.S.) Patent No. 10,877,083 on method of using partial voltage condition on 3 wire circuits to detect and localize wire down and other partial voltage conditions. Q3 2020/Q4 2020 Phase 2 Project Results: Meter firmware vendor contract finalized. Design of DMS data presentation for operator use. SmartMeter firmware functionality testing complete SmartMeter firmware deployment planning complete

TABLE:
SMARTMETER PARTIAL VOLTAGE DETECTION
(CONTINUED)

(iii).B: Lessons Learned	In Phase 1, it was discovered that some abnormal SmartMeter electric meter conditions (e.g., failed power supply) can produce false positive partial voltage alerts. PG&E had to address these false positives by applying filtering strategies to prevent presentation to operators through the DMS. In Phase 2, it was discovered that the filter needed to be reassessed because the system was alerting not just on primary open conductor issues, but also secondary or individual service issues that needed to be corrected through other means.
(iii).C: Quantitative Performance Metrics	Detection, analysis, and reporting of open jumpers, partial operation of unganged fuses, and wire down events. Target false positive rate: near zero though it may not be possible to get to zero due to operational conditions and technical limitations. Actual Results: No false positives have been detected. Number of minutes from the report of an event in advance of when a report would otherwise have been first received through existing processes. Target: Non-zero (any improvement in accurate advanced notice of an event contributes to risk reduction). Actual Results: Over 20 weeks in 2020 and 2021 the average number of minutes of advance notification from this system was 19.7 over a total of 1263 partial voltage-detected outages.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 1,475 Estimated RSE at Full Deployment: 1,077 Risk Drivers: Equipment Failure, Vegetation. Deployment Scope Assumption: System-wide. The risk mitigation potential is driven by the ability to reduce the likelihood of wildfire ignition risk through faster response time due to partial voltage and/or wire down conditions. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	As both phases of this project are now in production, current operational practices have been modified to include the functionality as described in this section (there are no additional findings).

TABLE:
SMARTMETER PARTIAL VOLTAGE DETECTION
(CONTINUED)

(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The methodology is to display filtered partial voltage alerts on transformers in DMS maps, which allows operators to be alerted of partial voltage conditions and visualize the boundaries between full voltage, partial voltage and complete outage sections of the distribution system. Integration into the Outage Management Tool will summarize SmartMeter partial voltage alert counts in an informational table presentation for current outages. The enhanced situational awareness can help operators detect and locate partial voltage line sections more quickly to enable faster response to potential wires down, open jumpers, or loss of phase(s) due to unganged fuse operation.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product was the deployment of the partial voltage detection firmware to all compatible PG&E SmartMeter electric meters system-wide, with system optimization completed, and functionality integrated into the DMS and Outage Management Tool, as described in (iv).B above.

TABLE:
LINE SENSOR DEVICES

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	Line Sensors are primary conductor-mounted devices that continuously measure current in real-time and report events as they occur, and in some cases the current waveform of grid disturbances. These line sensors are next-generation fault indicators with additional functionality and communication capabilities. Line Sensor technology can reduce wildfire risk and improve public safety by continuous monitoring of the grid, performing analytics on captured line disturbance data, identifying potential hazards, and when necessary dispatching field operations to proactively patrol, maintain, and repair discovered field conditions or assets on the verge of failure.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Line sensors have been deployed on 126 circuits covering a total of 11,896 circuit miles in Tier 2 & 3 HFTDs. On a daily basis, the data from these sensors are being used to investigate the source of unknown cause outages. Line sensor deployment on 67 additional circuits was completed in September 2021. PG&E continues to engage with other California and international utilities to discover and assess alternatives for monitoring technology.
(ii).C: Project Location	Tier 2 & 3 HFTDs in the North Bay, Sonoma, North Valley, Humboldt, Yosemite, De Anza, Los Padres, Central Coast, Stockton, and Sierra divisions.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Deployed line sensors to 34 additional circuits covering 3,742 line miles in Tier 2 & 3 HFTDs. Q2 2021 Deployed line sensors on 33 additional circuits covering 3,092 line-miles in Tier 2 & 3 HFTDs. Q1 2021 Line sensors for the planned 2021 deployment ordered and contract team engaged to manage deployment and commissioning. Q3 2020/Q4 2020 Developed line risk evaluations based on line sensor and other data for select HFTD circuits to calculate location of potential issues. Informed field operations for further inspection, assessment, and maintenance. Improved analytics methods and automation.

TABLE:
LINE SENSOR DEVICES
(CONTINUED)

(iii).B: Lessons Learned	When combined with other data sources, line sensor devices contribute valuable data to enable proactive condition detection. Inputs from other sensors and systems as well as analytics are required to improve accuracy and results. Additional setting tuning will improve results during protection changes for fast trip settings. More sensors may be needed to cover conditions during fast trip setting periods.
(iii).C: Quantitative Performance Metrics	Percentage (%) of the events detected by Line Sensors (e.g., grid disturbances from vegetation contact or line slap) resulting in identification of wildfire risk conditions requiring preventative action. Target: ≥50% Actual Results as of Nov 2021): 43% percent (118 events investigated with 50 risk issues found).
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 1,407 Estimated RSE at Full Deployment: 27 NOTE: This Estimated Potential Risk Reduction Score is for the combination of this Line Sensor Devices project and the DFA project also reported on in this section, as the technologies of these two projects work in concert to detect where the fault was located (Line Sensor Devices) and when the fault occurred (DFA). Risk Drivers: Equipment Failure, Vegetation, Consequence of Fire. Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs. This initiative, in concert with DFA as previously described, reduces the likelihood of ignition and consequence of fire risk, specifically mitigating the equipment failure, vegetation drivers and financial, safety, and reliability consequences. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	When a suspected high-risk condition is found by the Line Sensor Device team, the local restoration team is alerted and dispatched to patrol and rectify the situation as needed.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	PG&E is using data provided by line sensor technologies to bolster asset health and performance through a three-step process: (i) Collecting line sensor data attributes on disturbances to create a database of disturbance signatures for disturbance evaluations; (ii) Detecting disturbance information from Tier 2 and Tier 3 HFTDs and matching the captured disturbance data against the signature database to determine if a distribution line risk is likely to materialize as a hazard; (iii) Matching line sensor data attributes on line risks in a manner in which they can be evaluated in the distribution network

TABLE:
LINE SENSOR DEVICES
(CONTINUED)

	model software to estimate the location of the line risk for proactive field patrol, inspection, and repair, if necessary, before failure to reduce risk and improve system safety.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	This product is one component of a set of grid sensor technologies (as described in 7.3.2.2 Continuous Monitoring Sensors) that, as a set, are optimized to support and complement each other. This product would be deployed to circuits in Tier 2 & 3 HFTDs and would be integrated into Distribution Control Center (DCC), Maintenance, and Field Operations functions to support faster fault identification (including location data) for proactive maintenance prior to high fire risk periods.

TABLE:
EARLY FAULT DETECTION

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	The Early Fault Detection (EFD) project utilizes distributed sensors near transmission or distribution lines to detect radio frequency signals that are generated by potential latent or incipient issues in their early stages with the intent to be able to remove many of the conditions that can cause wildfires. EFD may also be able to more quickly detect and locate aggressively failing components during high-risk conditions and allow field crews and fire protection personnel to more immediately respond to and minimize wildfire risks.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	Deployment planning including contract negotiation, coordination with PG&E's Standards team, and the development of engineering processes.
(ii).C: Project Location	In general, distribution circuits with more than 3 line miles within Tier 2 or 3 HFTDs (the selection process for specific locations has not been completed at this time).
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Draft deployment standards were developed, and field surveys were completed on two circuits. Q2 2021 No results this quarter as the deployment is currently being planned.
(iii).B: Lessons Learned	None so far.
(iii).C: Quantitative Performance Metrics	Percentage (%) of the events detected by sensors resulting in identification of wildfire risk conditions requiring preventative action. Target: ≥50% Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 45,369 Estimated RSE at Full Deployment: 1,120 Risk Drivers: Equipment Failure, Vegetation, Consequence of Fire. Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs. This initiative reduces the likelihood of ignition and consequence of fire risk, specifically mitigating the equipment failure, vegetation drivers and financial, safety, and reliability consequences. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.

TABLE:
EARLY FAULT DETECTION
(CONTINUED)

(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	When a suspected high-risk condition is found by the project team, the local restoration team is alerted and dispatched to patrol and rectify the situation as needed.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	PG&E is using data provided by continuous monitoring sensor technologies such as EFD to bolster asset health and performance in the distribution network model software to estimate the location of the line risk for proactive field patrol, inspection, and repair, if necessary, before failure in order to reduce risk and improve system safety.
(v).A: 'End Product' at 'Full Deployment' and Location	This product is one component of a set of grid sensor technologies (as described in 7.3.2.2 Continuous Monitoring Sensors) that, as a set, are optimized to support and complement each other. This product would be deployed to circuits in Tier 2 & 3 HFTDs and would be integrated into Distribution Control Center (DCC) Maintenance, and Field Operations functions to support faster fault identification (including location data) for proactive maintenance prior to high fire risk periods. If the technology is determined to be operationally viable, the intent is to deploy EFD (along with DFA) sensors on a total of 600 to 800 circuits in Tier 2 and Tier 3 HFTD areas, mitigating 28,000 total line miles (20,200 miles in Tier 2, 7,800 miles in Tier 3).

TABLE:
DISTRIBUTION FAULT ANTICIPATION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	DFA technology captures primary distribution disturbance current and voltage waveforms. It conducts digital signal processing locally, communicates results to a waveform classification engine which then identifies both normal and abnormal events on the distribution system. The DFA technology is installed within the substation and uses existing substation bus Potential Transformers and circuit breaker Current Transformers (CT). When combined with Line Sensor Devices data the technologies of these two projects work in concert to detect where the fault was located (Line Sensor Devices) and provide a precise time of when the fault occurred (DFA).
(i).C: UWMMM Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Design/ Engineering
(ii).B: Project Status	Deployment planning in progress.
(ii).C: Project Location	The selection process for specific locations has not been completed at this time, though it is known that the installation locations will be at substations in Tier 2 and Tier 3 HFTD areas.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Draft standards were developed, and job packages created for five scheduled installations. Q2 2021 No results this quarter as the deployment is currently being planned.
(iii).B: Lessons Learned	None so far.
(iii).C: Quantitative Performance Metrics	Percentage (%) of the events detected by sensors resulting in identification of wildfire risk conditions requiring preventative action. Target: ≥50% Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 21,881 Estimated RSE at Full Deployment: 409 NOTE: These scores are for the combination of this DFA project and the Line Sensor Devices project also reported on in this section, as the technologies of these two projects work in concert to detect where the fault was located (Line Sensor Devices) and when the fault occurred (DFA).

TABLE:
DISTRIBUTION FAULT ANTICIPATION
(CONTINUED)

	Risk Drivers: Equipment Failure, Vegetation, Consequence of Fire Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs This initiative, in concert with Line Sensor Devices as previously described, reduces the likelihood of ignition and consequence of fire risk, specifically mitigating the equipment failure, vegetation drivers and financial, safety, and reliability consequences. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	When a suspected high-risk condition is found by project team, the local restoration team is alerted and dispatched to patrol and rectify the situation as needed.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	PG&E is using data provided by continuous monitoring sensor technologies such as DFA to bolster asset health and performance through a three-step process: (i) Collecting sensor data attributes on disturbances to create a database of disturbance signatures for disturbance evaluations; (ii) detecting disturbance information from Tier 2 and Tier 3 HFTDs and matching the captured disturbance data against the signature database to determine if a distribution line risk is likely to materialize as a hazard; (iii) matching sensor data attributes on line risks in a manner in which they can be evaluated in the distribution network model software to estimate the location of the line risk for proactive field patrol, inspection, and repair, if necessary, before failure to reduce risk and improve system safety.
(v).A: 'End Product' at 'Full Deployment' and Location	This product is one component of a set of grid sensor technologies (as described in 7.3.2.2 Continuous Monitoring Sensors) that, as a set, are optimized to support and complement each other. This product would be deployed to circuits in Tier 2 & 3 HFTDs and would be integrated into DCC, Maintenance, and Field Operations functions to support faster fault identification (including location data) for proactive maintenance prior to high fire risk periods. The intent is to deploy DFA (along with EFD) sensors to monitor a total of 600-800 circuits in Tier 2 and Tier 3 HFTD areas, mitigating 28,000 total line miles (20,200 miles in Tier 2, 7,800 miles in Tier 3).

TABLE:
EPIC 3.45: AUTOMATED FIRE DETECTION FROM WILDFIRE ALERT CAMERAS

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	The existing PG&E wildfire camera infrastructure, part of the ALERTWildfire network (http://www.alertwildfire.org), is a passive and human-operated system. Cameras are manually operated and utilized to confirm satellite heat detections or Integrated Reporting of Wildland-Fire Information (IRWIN) alerts. It is extremely important to identify the location of an ignition in the initial stage of a wildfire to suppress it while the scale is manageable. The current process of starting with the IRWIN alerts, and then visually confirming ignitions with cameras can be improved upon to expedite the initial response time, which is currently dependent on human operator limitations. This project aims to demonstrate reduced ignition-to-detection time capability with low false positive and false negative rates by building upon two existing tests and prior academic research for enhanced situational awareness. The project also seeks to investigate novel techniques for integrating this intelligence into the PG&E Hazard Awareness and Warning Center (HAWK) capabilities and workflow with the intent to provide faster, more accurate, and more automated fire detection functionality. In addition, the project will evaluate advanced features such as nighttime detection, viewshed analysis, and triangulation accuracy.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	B. Situational awareness and forecasting 10.Wildfire detection processes and capabilities
(ii).A: Project Phase	Planning
(ii).B: Project Status	As the project had just been approved at the time of preparation of this report, the project is in the process of team formation and organization.
(ii).C: Project Location	The expected project locations are Tier 2 and Tier 3 HFTDs and possibly Tier 1 HFTD locations that offer views of potential fire spread into Tier 2 and Tier 3 HFTDs.
(iii).A: Results to Date	There are no results as the project has just been approved.
(iii).B: Lessons Learned	There are no lessons learned as the project has just been approved.
(iii).C: Quantitative Performance Metrics	Average time between ignition and automated detection. Target: ≤ 3 mins Actual Results: None so far Average distance between reported location and actual location. Target: ≤ 1 mile Actual Results: None so far False positive rate. Target: ≤ 1% Actual Results: None so far

TABLE:
EPIC 3.45: AUTOMATED FIRE DETECTION FROM WILDFIRE ALERT CAMERAS (CONTINUED)

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 32,156 Estimated RSE at Full Deployment: 2,973 Risk Drivers: Consequence of Fire Deployment Scope Assumption: Systemwide with a focus on Tier 2 and Tier 3 HFTDs. This initiative reduces the consequence of fire by enabling first responders to respond to a new fire sooner when the fire is smaller and more manageable. This initiative will also enable quicker PG&E response to mitigate any risks associated with PG&E assets. To achieve this, the project seeks to reduce the average time between ignition and automated detection to less than 3 minutes and to reduce the average distance between reported location and actual location to less than 1 mile. This technology aims to complement other forms of fire detection platforms, such as satellite data, to detect fires as fast as possible.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	No findings so far.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Establish user acceptance criteria from the HAWC to integrate the AI technology into the existing technology landscape. The criteria includes an understanding of how AI information will complement the information in the current Wildfire Incident Viewer (WIV) dashboard and the ALERTWildfire network.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	An integrated automated wildfire detection solution with additional improvements identified during the demonstration, additional integration capabilities identified during the demonstration, and a system that can quickly and reliably detect wildfires automatically with minimal human interference.

<u>Program Area</u>: Grid Design and System Hardening—New or Emerging Technologies

PG&E is reducing the risk of fire ignition and potential impacts on public safety through the adoption of system hardening methods enabled through innovative technologies (e.g., new grid topologies or new resilience and Public Safety Power Shutoff (PSPS) avoidance technologies or techniques). Mitigations leveraging new or emerging technologies include the following:

**TABLE:
EPIC 3.15: PROACTIVE WIRES DOWN MITIGATION DEMONSTRATION PROJECT
(RAPID EARTH FAULT CURRENT LIMITER)**

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	The EPIC 3.15 Proactive Wires Down Mitigation demonstration project seeks the ability to automatically and rapidly reduce the flow of current and risk of ignition in single phase to ground faults through the use of Rapid Earth Fault Current Limiter (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 arcing and fire ignitions, as well as better detection of high impedance faults and wire-on-ground conditions. REFCL technology is applicable to three-wire uni-grounded circuits, which make up the majority of PG&E's distribution circuits within HFTDs.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 14. Risk-based grid hardening and cost efficiency 15. Grid design and asset innovation
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	After commissioning and during the first field test, the failure of a piece of equipment within the REFCL system temporarily halted testing and demonstration. A design change in the substation is underway to mitigate the failure and allow for the REFCL to go back in service for completion of the remaining testing and demonstration, targeting closeout in June 2022. Based on feedback from Australian utilities who have leveraged this technology, ongoing observation and adjustment of various system parameters may be needed to "fine-tune" the REFCL system going forward. Evaluation of additional substations for suitability of additional REFCL installations has begun but is pending results and learnings of the initial EPIC project before design or field work starts on additional sites. After an initial screening process, 25 distribution substations with circuits in HFTDs are candidates for potential REFCL deployment.
(ii).C: Project Location	Substation in a Tier 3 HFTD in the North Bay.

TABLE:
EPIC 3.15: PROACTIVE WIRES DOWN MITIGATION DEMONSTRATION PROJECT
(RAPID EARTH FAULT CURRENT LIMITER)

(iii).A: Results to Date	Q3 AND OCTOBER 2021 The 2021 WMP commitment in 7.3.3.17.4 was satisfied. REFCL equipment failures temporarily halted the testing and demonstration. Design changes for the substation were finalized with construction beginning October 2021 to implement the updated design. Q2 2021 Substation and distribution commissioning completed. First staged fault test successfully performed. Q1 2021 Completed Substation Supervisory Control and Data Acquisition (SCADA), and Substation fire alarm system certification. Q4 2020 Completed substation construction and all the distribution field installations in Q4 2020.
(iii).B: Lessons Learned	After encountering the REFCL equipment failures, the design was changed to directly connect the Arc Suppression Coil (ASC) to the substation bank neutral bus instead of using a grounding transformer for creating a path for the ground current. Unbalanced load currents were observed during the summer peak loading, so some phase connections are being swapped at two locations to better balance the loads and improve sensitivity of the REFCL scheme. The original configuration of the Ground Fault Neutralizer (GFN) installation in the substation resulted in ferroresonance issues, which had to be mitigated. Additional preventive measures were needed to avoid ferroresonance and equipment damage resulting from the transient overvoltages. Some of these measures include use of a 3-phase recloser to protect the 12 kilovolt (kV) service going to the GFN equipment, relocation of the substation service transformer, and using Type B voltage regulators or transformer banks with Load Tap Changer capability for voltage regulation. The GFN adds on another layer of system protection with greater sensitivity to ground faults than traditional system protection schemes commonly used in the USA which utilize solid grounding. In digital simulation testing, the GFN showed the capability to detect high impedance ground faults upwards of 16K ohms, which is in the typical range for vegetation contact faults. The GFN also shows promise of detecting reverse earth faults resulting from specific wires-down situations, which are especially challenging to detect and pose a public safety risk.

	A key lesson learned is the need for balancing the line to ground capacitance of each phase on the distribution circuits where a GFN is deployed. A detailed review was performed in the project and it highlighted the need for capacitive balance units to have precise control over the balancing and achieve the greatest fault sensitivity. Group tapping for line voltage regulators was also determined to be required, so a new multiphase regulator controller was tested and verified for this function.
(iii).C: Quantitative Performance Metrics	Ignition probability reduction with field test results per the Energy Safe Victoria (ESV, Australia) REFCL standard as follows: Faulted conductor voltage < 1,900 V within 85 milliseconds Faulted conductor voltage < 750 V within 500 milliseconds Faulted conductor voltage < 250 V within 2,000 milliseconds Target: ≥ 90 percent Actual Results: 100 percent (1 test series). In the first staged fault test series with resistance of 3200 ohms (see the discussion of high impedance faults in the Lessons Learned section above), a momentary high impedance fault was created on the distribution line using a mobile high voltage resistor bank connected to ground. The GFN successfully detected the fault, reduced the voltage on the faulted phase, and correctly identified that the fault was on the specific feeder. Measured voltages of the faulted phase from the test were 1679V at 85 milliseconds, 225V at 500 milliseconds, and 224V at 2000 milliseconds, all of which meet the ESV standard referenced above. False positive rate Target: ≤ 10% Actual Results: Not available at this time. False negative rate Target: ≤ 5% Actual Results: Not available at this time. GFN system availability/uptime (excluding external operations constraints) Target: ≥ 95% Actual Results: Not available at this time. Correct identification of faulted circuit and feeder breaker tripping Target: ≥ 95% Actual Results: Not available at this time.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 6,981 Estimated RSE at Full Deployment: 40 Risk Drivers: Equipment Failure Deployment Scope Assumption: 25 distribution substations serving ~4,000 miles of 3-wire/12kV distribution lines in Tier 2 & 3 HFTDs.

TABLE:
EPIC 3.15: PROACTIVE WIRES DOWN MITIGATION DEMONSTRATION PROJECT
(RAPID EARTH FAULT CURRENT LIMITER)

	The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The GFN will be operational in the North Bay substation to add another layer of system protection to the two connected distribution circuits. If a ground fault is detected, the GFN will autonomously mitigate the fault current and identify which circuit the fault is on. Pre-defined criteria will determine how the fault is cleared, whether through recloser tripping or cutover to solid grounding depending on ambient conditions. The plan for additional production implementations of the technology is in development.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	A Substation Earth Fault Management relay interface controller is currently in development and is needed to integrate the GFN into operational practices and the SCADA system. Operators will have visibility into the status of the GFN and make control decisions if a fault is detected. Training sessions with operations personnel are being scheduled showing how the REFCL technology works and the associated controls.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product is that the REFCL system would be deployed to substations in Tier 2 and 3 HFTDs, including substation components (arc suppression coil, GFN control cabinet, residual current compensator, and potentially upgraded CTs and relays) and field work (capacitive balancing, upgraded line reclosers, and upgrades to regulators, capacitor banks, and insulation levels as needed). Capacitive planning incorporated into annual distribution planning cycle. Capacitive operational analysis incorporated into planning and analysis of planned and unplanned outages. Annual training for field personnel who would interact with the system, distribution operations, and distribution engineering. Annual testing of circuit and REFCL system to check reliability/sensitivity of REFCL system operations and insulation tests to detect equipment that is overly stressed and likely to fail during REFCL operation.

**TABLE:
DISTRIBUTION, TRANSMISSION, AND SUBSTATION: FIRE ACTION SCHEMES AND TECHNOLOGY (DTS FAST)**

Note: Due to the sensitive nature of the experimental, proprietary technology, PG&E is unable to disclose extensive details about the DTS-FAST project in public filings. Upon request, PG&E can provide further information under confidentiality protections.

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	DTS-FAST is an internal PG&E wildfire mitigation development project. This project aims to use real-time technologies to detect objects approaching energized power lines and respond quickly to shut off power before object impact. PG&E is engineering, constructing, installing, and monitoring DTS-FAST technology on PG&E transmission and distribution circuits to assess the technology's efficacy at mitigating PG&E's wildfire and safety risks. Next steps and potential operationalization of this technology is dependent on an assessment of findings.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 15. Grid design and asset innovation
(ii).A: Project Phase	Closeout (initial installation). Planning (additional wood pole installation).
(ii).B: Project Status	The prototype field test installation at the Santa Cruz Service Center is complete, and the team is working with the PG&E standards organization on approval of the final version.
(ii).C: Project Location	The initial installation was on 115kV transmission towers in Contra Costa County, and an installation on wood poles is planned in Santa Cruz County in 2022.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 The distribution prototype field test installation at the Santa Cruz Service Center is now complete. Q2 2021 Finalized design of the DTS-FAST transmission system and started manufacturing of the devices for the next planned installations. Q1 2021 Testing of the initial installation on 115kV transmission towers in Contra Costa County is complete. Additional installations on 115kV transmission towers (Amador County) and distribution poles (Butte County) are in a planning and environmental impact analysis phase. Q3 2020/Q4 2020 Engineering and construction details completed for pilot on 115kV transmission circuit.

(iii).B: Lessons Learned	We learned that the system as designed is capable of being installed by crews onto an existing transmission tower, can operate in the high electromagnetic field environment of a transmission tower, and can withstand inclement environmental conditions.
(iii).C: Quantitative Performance Metrics	The detection of objects approaching energized power lines and the corresponding power shut off. Target: Power shut off prior to object impact. Actual Results: Confidential.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: Confidential Estimated RSE at Full Deployment: Confidential Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: System-wide The risk mitigation potential is driven by the ability of the new technology to effectively shut off power to distribution and transmission lines as failures are detected by its sensors.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	None to date.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Leverage project findings for operational implementation. Monitor new installations and assess success criteria to ensure technology is working optimally. Assess impacts on asset inspections enabled through real time sensor data. Assess impacts on ability to reduce PSPS events and expedite restoration times.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	Full deployment plans will be dependent on findings. If successful, PG&E will consider a targeted approach for implementation to help ensure high impact areas are first addressed, taking into account risk-based and feasibility assessments.

TABLE:
REMOTE GRID

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	A “Remote Grid” is a new concept for utility service using standalone, decentralized energy sources and utility infrastructure for continuous, permanent energy delivery in lieu of traditional wires to small loads in remote locations at the edges of the distribution system. In many circumstances, the feeders serving these remote locations traverse through HFTDs areas. If these long feeders were removed and the customers served from a local and decentralized energy source, the resulting reduction in overhead lines could reduce fire ignition risk as an alternative to or in conjunction with system hardening. In addition to reducing wildfire risk, Remote Grid could be a cost-effective solution against expense and capital costs for the rebuild of fire-damaged infrastructure or for HFTD hardening infrastructure jobs to meet new HFTD build standards. PG&E’s Remote Grid Initiative will validate and develop Remote Grid solutions as standard offerings such that they can be considered alongside or as an alternative to other service arrangements and/or wildfire risk mitigation activities such as system hardening. The Remote Grid Program has developed the Briceburg Remote Grid project to achieve these goals. The findings of other pilot or demonstration projects, including EPIC 3.03: Advanced Distribution Energy Resource Management System, which looks to develop increased situational awareness and control capabilities of DERs, will help to support the deployment of remote grid configurations.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 13. Grid design for resiliency and minimizing PSPS 14. Risk-based grid hardening and cost efficiency
(ii).A: Project Phase	Closeout
(ii).B: Project Status	PG&E completed commissioning on its first project, the Briceburg Remote Grid, which went operational on June 3, 2021. The Remote Grid facilitated restoration of service to 5 customers who lost power due to the Briceburg fire in 2019. The Briceburg Remote Grid has over 4,000 hours of safe, operational, and uninterrupted runtime. With 1 system online, Remote Grid is graduating to a program and will no longer be tracked in this section of the WMP (see Initiative 7.3.3.17.5). The Remote Grid program is advancing new projects through scoping, assessment, contracting, design, and permitting activities, based on the lessons learned from the success of this initial Project.
(ii).C: Project Location	The Briceburg Remote Grid project is located near Midpines, California in Mariposa county.

TABLE:
REMOTE GRID
(CONTINUED)

(iii).A: Results to Date	Q3 AND OCTOBER 2021

TABLE:
REMOTE GRID
(CONTINUED)

	The Briceburg project is in the Closeout phase; results are complete. Results associated with the other Remote Grid projects described below are detailed in Initiative 7.3.3.17.5. Operated the Briceburg Remote Grid for 4000 total hours in this reporting period with 100% uptime and performed successful live automated source transitions between inverters and generation resources. Developed decision-making criteria for de-energization of the Briceburg Remote Grid during PSPS events if required. This site was never in PSPS scope during the 2021 fire season and was not de-energized. Successfully performed the first semiannual preventative maintenance of the operational Briceburg Remote Grid. Completed a Failure Modes and Effects Analysis risk assessment and Hazard Identification Process for PG&E's initial Standalone Power System design. This facilitated improvements to system design and a quantification of system risk relative to other electric distribution assets. Developed a solicitation package for an RFP to identify a standardized remote monitoring platform, expected to be a software tool critical to future iterations of PG&E’s design specification. This operational technology aims to deploy consistent fleet monitoring across SPS units and among all installation vendors. Solicitation start is planned for late 4Q 2021, with award in 2022. Initiated customer outreach stage for a further set of Remote Grid projects to deploy refined methods for customer engagement and project execution. Projects which successfully progress through the early stages of project development will be continued in Initiative 7.3.3.17.5 Q2 2021 Completed the Briceburg Remote Grid project, including all construction, commissioning, and performance testing, with customers energized in June. 2021 Request for Proposals (RFP) process completed for six Standalone Power System (SPS) units (one of the six was subsequently descoped due to changing customer needs), with the remaining five entering final contract negotiations to complete award for SPS installation and maintenance agreements. Scoped and progressed 11 fire rebuild projects through customer outreach stage in North Complex Fire footprint in Butte County. None of these projects moved to SPS deployment stage, due to various factors including particular project economics and lack of customer acceptance at these specific sites. Identified, scoped, and drove 5 new 2021 Remote Grid projects (7 SPS total) through project assessment process including: customer engagement and approval, Wildfire Governance Committee approval, advanced budget authorization, and final project scoping and financial analysis.

	Released 2021 RFP (5 projects, 7 SPS) bundle to vendor bid. Completed shortlisting of bidders and scheduled interviews with goal of awarding contracts in Q2. (One of the seven SPS was subsequently deferred for later deployment by request of the customer landowner to be served.) Obtained California Public Utilities Commission (CPUC) approval for Supplemental Provisions and other key program regulatory elements via Resolution E-5132 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M371/K108/371108623.PDF). Land rights and customer engagement process refinement to support scaling up of 2022 scope. Q4 2020 Negotiated & executed a turnkey Purchase and Sale Agreement and a 10- year full-wrap Maintenance Agreement, forming a reusable template for future SPS procurements. Drafted terms of service into a form of Supplemental Provisions to the Electric Rules, as a tariffed form agreement. The majority of customers engaged to date have voiced positive initial interest in pursuit of service conversion from overhead line to a Remote Grid. Filed the proposed form of Supplemental Provisions Agreement with the CPUC in Advice 6017-E[1] on December 15, 2020. Benchmarking with other utilities shows a point of validation in the advanced program now operational under Horizon Power in Western Australia. In California, Liberty Utilities has procured its first SPS for a similar application. Q3 2020 Developed and awarded major update of contract, including updated technical specification. Documented detailed screening protocol to identify and evaluate potential projects. Q2 2020 Completed field site visits to identify additional projects to pursue for concept validation. Completed first broad RFP solicitation which was received by more than 20 technology integration and construction vendors, delivering initial validation of commercial availability.

1 See Advice 6017-E “Remote Grid Standalone Power System Supplemental Provisions Agreement” https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6017-E.pdf.

TABLE:
REMOTE GRID
(CONTINUED)

(iii).B: Lessons Learned	Failure Modes and Effects Analysis (FMEA) consultant concludes that PG&E has followed industry standards, codes, and best practices in designing SPS. Report includes actionable recommendations for SPS operations and future design refinements, serves as a basis for maintenance and inspection checklists, highlights historically relevant common points of failure, and informs future asset management, risk data analytics, and specification development. In the fire rebuild context, several rebuild-specific conditions can reduce individual project feasibility or delay implementation. Examples include: difficulty in reaching customers who have been impacted by wildfire; varying customer timeline needs across the same line segment, (e.g., immediate power needs for some customers and no near-term power needs for neighbors); and unforeseen changes in post-wildfire customer loads that impact projected Remote Grid project economics vs initial screening. PG&E identified the technology combination of Solar Photovoltaic Generation and Battery Energy Storage with supplemental Propane Generators as the most cost effective, reliable, and cleanest solution for initial Remote Grid sites. PG&E found there was sufficient initial vendor interest and availability to engage in contracting to deploy systems with specifications and terms responsive to PG&E's requirements. A number of site-specific conditions can reduce individual project feasibility or delay implementation. Examples include: customer acceptance, physical space constraints, shading and other constructability related considerations such as grading and geological conditions, permitting challenges such as presence of threatened species, cultural heritage, or adjacency to scenic highway. Development of the Briceburg Remote Grid helped the Remote Grid Program refine its design criteria and development process through close coordination with the project vendor and internal stakeholders. The Remote Grid Program has also developed an internal operational model for lifetime ownership and maintenance of Remote Grids for the Briceburg SPS that will be applied to future projects in the Program as they come online.
(iii).C: Quantitative Performance Metrics	Safe operating hours (e.g., five SPS units for one year) without a safety or fire incident. Target: ≥ 50,000 hours Actual Results: >4000 unit-hours (continuous operation of the Briceburg SPS unit) as of October 2021 Portfolio uptime, average Target: ≥ 99% Actual Results: 100% (no SPS outages in the reporting period) Percent (%) Renewable Fraction of portfolio on average, with each SPS meeting applicable California Air Resources Board (CARB) emissions limits. Target: ≥ 60% Actual Results: 98.9%

TABLE:
REMOTE GRID
(CONTINUED)

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 1,584 Estimated RSE at Full Deployment: 9 Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: 452 miles of distribution lines in Tier 2 & 3 HFTDs, and 23.8 miles of distribution lines in Non-HFTD areas. The risk mitigation potential is driven by the ability to eliminate overhead feeder lines and therefore should address virtually all risk drivers, noting however that since remote grids serve multiple customers there are still potential points of failure and ignition risk in that local area. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The Briceburg Remote Grid project is now a fully featured, long-term asset deployment that has allowed PG&E to eliminate 1.37 miles of overhead line exposure. Beginning in June 2021 when the project went online, an immediate ignition risk reduction can be realized upon de-energization and subsequent removal of the overhead conductor the project replaced. This risk reduction is estimated at 98.3% for the Briceburg project as compared with restoration of bare overhead wire. This value is based on 100% risk mitigation for the wires removed, plus a 1.7% risk value per SPS unit as derived from the Remote Grid Program FMEA and PG&E conductor risk modeling.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Standardization of Remote Grid site assessment and deployment processes, technical specifications, vendor contract templates, identification of qualified providers, and operational protocols (e.g., outage detection and response coordination) are underway enable more rapid deployment of potential future Remote Grids. Further validation of the actual costs and lead time to deliver utility-grade performance and reliability will enable understanding of how widespread the benefits of this approach may be, relative to the occurrence of the requisite grid topology existing on the PG&E distribution system today. For instance, a Remote Grid is most likely to be appropriate at the end of an overhead distribution feeder with small numbers of customers.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	Based on the success of this Remote Grid project, the Remote Grid Program is developing additional project sites and building the program towards a standard service offering that is considered alongside other risk mitigations, such as overhead hardening and undergrounding. PG&E will deploy Remote Grids wherever it is cost effective and feasible as compared with alternative hardening solutions. Deployment locations will be at the ends of overhead distribution feeders that serve small numbers of customers in HFTDs. Future project work can be found in Initiative 7.3.3.17.5.

TABLE:
EPIC 3.11: MULTI-USE MICROGRID

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	The EPIC 3.11: Multi-Use Microgrid demonstration project develops and tests the technology, processes, and business models needed to deploy and operate multi-customer microgrids that are integrating third party-owned renewable energy generation assets to power the microgrid on a section of PG&E's distribution system. This includes the design and development of control specifications and System Control and Data Acquisition (SCADA) integrations to maintain visibility and operational control of the microgrid in grid-connected and islanded modes. The findings of this project will help support microgrid growth to further resiliency and enhanced customer choice.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 13. Grid design for resiliency and minimizing PSPS
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Functional design specification for the microgrid controller and the end to end integration network architecture and security approach have been finalized. Operational decisions for the microgrid including for communication and hardware fail-safes were evaluated in order to prepare the microgrid for integration at the Distribution Control Center (DCC). This specification along with the completed Concept of Operations (CONOP) documentation is now being used to complete PG&E's advanced microgrid testbed. This pilot is progressing towards broader adoption, including creating standards and tariffs that would be needed to enable PG&E to partner with third parties (such as communities) and deploy microgrids.
(ii).C: Project Location	McKinleyville (Humboldt County). The project, the Redwood Coast Airport Microgrid, serves the Arcata-Eureka Airport business community incorporating 18 PG&E and Redwood Coast Energy Authority customers, including critical facilities such as the airport and a U.S. Coast Guard station.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Released the final version of the Description of Operations which serves as the foundational document for utility procedure documentation. Completed PG&E site construction and installed the islanding recloser controller. Completed bench testing of the islanding recloser at an Advanced Technology Services (ATS) location and successfully developed the recloser SCADA screens. Completed recloser field commissioning and point-point testing to the Distribution Control Center. Kicked off Advanced Testing using a Power-Hardware-in-the-Loop testbed at an ATS location. Successfully carried out load test for grid-connected mode; gain permission to operate as a distributed generator.

	Q2 2021 Completed the Microgrid Description of Operations. Completed Factory Acceptance Testing at microgrid controller manufacturer's site. Developed DCC SCADA screens to enable remote monitoring and control. Developed onsite Human-Machine Interface (HMI) screens to enable local control. Completed the configuration of the Advanced Microgrid Test Bed at a PG&E test facility. Q1 2021 Released initial draft of Microgrid Description of Operations for technical review. Completed control logic configuration of microgrid controllers and onsite HMI. Kicked off Operational Integration activities with PG&E Business Application and field personnel to design devices, interfaces and processes for microgrid telemetry and control. Q4 2020 Configuration of information points list and HMI. Controller Test Plan aligned with third-party manufacturer. Utilized lessons learned from this project to publish a Community Microgrid Technical Best Practices Guide. Q3 2020 Started SCADA design (in progress). Refined Functional Design Specification. Completed communication and hardware fail-safes decisions. Prior Results Provided key feedback to microgrid controller manufacturers to inform the development of the Functional Design Specification document. Developed guideline questions for future microgrid controller testing beyond this project in order to support standardization.
(iii).B: Lessons Learned	In order to ensure reliability and mitigate customer power loss, circuits should be designed to allow microgrid mode transitions to be seamless if possible.

TABLE:
EPIC 3.11: MULTI-USE MICROGRID
(CONTINUED)

	Verify prior to system design that preferred resilient communication systems, such as the Field Area Network (FAN), are available. Ensure clear designation and separation of stakeholder responsibilities, particularly between the utility and the microgrid generation owner/operator. Defining if microgrid will be allowed to operate under certain fail-safe conditions requires strong operator buy-in and participatory planning. The process used for this project can serve as a useful guide for future microgrid deployment. Because each microgrid configuration is unique it may not be possible to fully standardize and streamline processes and technology to be applicable for all microgrids. Future frameworks will need to be flexible to accommodate unique project needs. Future project economics will likely differ significantly from the EPIC-funded Redwood Coast Airport Microgrid project and could be a major barrier to future scalability of multi-customer microgrids.
(iii).C: Quantitative Performance Metrics	Ability of the microgrid to safely and seamlessly energize the island and provide electric service throughout the duration of broader multi-hour grid outages. Target: Pass Actual Results: Metric result will be available after the microgrid is commissioned.
(iii).D: Quantitative Risk Reduction Benefits	Quantitative Risk Reduction Benefits cannot be calculated for these types of third-party microgrids as PG&E does not determine if or where such a microgrid is constructed.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	Controller testing in PG&E's Microgrid Test Bed is being designed to be replicable and scalable to a wide range of microgrid controllers. This will facilitate the deployment of control schemes for future microgrid sites.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	This project is designing the microgrid to be visible and controllable from the PG&E control center. Its operational guidebook will be the basis for integrating future microgrids of this kind into the control center operations. A microgrid operating agreement is being developed and will form the basis of similar agreements for future community microgrids.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product is the formalization and documentation of a repeatable operational process that will enable a streamlined approach to deploying additional Multi-Use Microgrids as appropriate in HFTDs.

TABLE:
EPIC 3.11B: CONTROL OF BTM DERs

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	This Control of BTM DERs project, an expansion of EPIC 3.11, will develop the technical capabilities and the production-ready operational processes to utilize Behind the Meter (BTM) DERs for resiliency in microgrids with the following three objectives: Objective #1: Demonstrate that BTM DERs can support microgrid resiliency for cleaner PSPS. Objective #2: Enable higher penetrations of BTM DERs in multi-customer microgrids (e.g., Community Microgrid Enablement Program). Objective #3: Demonstrate the coordination of BTM DERs with Front of the Meter distributed generators coupled with batteries.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 13. Grid design for resiliency and minimizing PSPS
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	The deployment of a microgrid in Placer County was completed, a simulation was run, and an evaluation of the results was started.
(ii).C: Project Location	Placer County
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Deployed battery-plus-diesel generation microgrid at a site in Placer County with 200% BTM penetration of generation to load. The site utilized a conventional control system with communication amongst the battery, generator, and load bank (not the EPIC 3.11B control system). A 48-hour PSPS simulation and solar ramping/tripping test was conducted. Weaknesses in the control system were observed such that the site would function though not with optimally-low emissions. The evaluation of performance issues with high BTM PV generation in a microgrid has been initiated; the resulting analysis will address the following: Power flows during simulation Performance during PV trip/ramp Design configuration shortfalls and learnings for improvement Learnings from the initial 2021 demonstration will inform the preparation for testing the 2022 demonstration utilizing the frequency-control scheme (the focus of this project) that will be incorporated into the EPIC 3.11B control system. Q2 2021 Kicked off the project. Completed a high-level scoping analysis of control system and protections approach.

TABLE:
EPIC 3.11B: CONTROL OF BTM DERs
(CONTINUED)

(iii).B: Lessons Learned	None so far.
(iii).C: Quantitative Performance Metrics	Reduction in diesel generation run-time and emissions (using 2021 as the baseline). Target: >20% reduction for sites with DER shutoffs Actual Results: 2022 results to be available after 2022. Reduction in curtailment hours for DERs (using 2021 as the baseline). Target: >20% reduction. Actual Results: 2022 results to be available after 2022. Reduction in Number of DER sites shut down for PSPS (using 2021 as the baseline). Target: >20% reduction. Actual Results: 2022 results to be available after 2022.
(iii).D: Quantitative Risk Reduction Benefits	Quantitative Risk Reduction Benefits cannot be calculated for BTM DERs as PG&E does not determine if or where such BTM DERs are constructed.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	TBD
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	TBD
(v).A: 'End Product' at 'Full Deployment' and Location	Technical capabilities and production-ready processes to utilize BTM DERs for resiliency in microgrids, including the core technology enabling the networking of microgrids at scale. Potentially applicable to any in-Front-of-The-Meter (FTM) microgrid with significant (>50% penetration) of BTM DERs, both for PSPS resiliency and other multi-customer microgrid use cases such as those that are part of the Community Microgrid Enablement Program (CMEP). At scale, the results of this project could allow for the seamless disconnection and reconnection of substation islands (provided sufficient substation energy storage existed) through loss of transmission while utilizing BTM DERs as the generation source.

TABLE:
CLEAN GENERATION FOR PSPS

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	The project objective is to reduce PG&E's reliance on diesel-fired generation for PSPS mitigation. PG&E is committed to moving toward a cleaner portfolio of generation solutions for reducing impacts of PSPS, including: expanding the pool of contractors and technologies, piloting viable non-diesel technologies in 2021, and exploring opportunities to build a portfolio of non-fossil solutions for the longer term. The term "generation" in this case is shorthand for in-Front-of-The-Meter (FTM) generation, demand response (DR), and Behind The Meter (BTM) generation. There are two types of pilots that are part of this project: Hybrid Temporary Generation Pilots at Distribution Microgrids PG&E piloted hybrid temporary generation solutions pairing inverter-based technologies with diesel generators at two Distribution Microgrids in 2021. The intent was to increase PG&E's and vendors' experience deploying hybrid temp gen solutions for PSPS mitigation, test the viability of these configurations, and inform future efforts to develop workable, cost-effective solutions that accelerate the integration of non-diesel generation technology for PSPS mitigation and other wildfire safety-related outages. See EPIC 3.11B Control of BTM DERs report in this section for more information on one of the two projects. Substation DR Pilots PG&E would like to explore the effectiveness of DR as a tool to reduce run-time of temporary generation for PSPS mitigation, thereby reducing operational costs and emissions (both local criteria pollutants and global greenhouse gases). Two existing DR programs, the Base Interruptible Program and Smart AC, have been identified as a strong starting point. A Tier 3 Advice Letter was filed on June 9, 2021 requesting timely CPUC approval of the use of these two DR programs during PSPS events that lead to the energization of temporary generation at the three substations. If successful, additional substations could be added to the program in 2022. These two pilot types are described and reported on separately below.

TABLE:
CLEAN GENERATION FOR PSPS
(CONTINUED)

(i).C: UWMMM Categories & Capabilities Potentially Impacted	N/A
(ii).A: Project Phase	Hybrid Temporary Generation Pilots at Distribution Microgrids: Closeout Substation DR Pilots: Build/Test
(ii).B: Project Status	Hybrid Temporary Generation Pilots at Distribution Microgrids: PG&E and its vendor partners intend to run multiple simulations to test the operational performance of both technology pilots, demobilized the sites, and close out the project. Substation DR Pilots: The CPUC approved the use of DR programs for Clean Substation Microgrid Pilot in Resolution E-5164.
(ii).C: Project Location	Hybrid Temporary Generation Pilots at Distribution Microgrids: Napa and Placer counties. See EPIC 3.11B Control of BTM DERs report in this section for more information on the project in Placer County. Substation DR Pilots: Nevada and Sonoma counties.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Hybrid Temporary Generation Pilots at Distribution Microgrids: PG&E and its vendor partners negotiated and executed energy-as-a-service contracts, completed engineering & design, and installed equipment to commission hybrid technology projects at the two Distribution Microgrids. See the EPIC 3.11B Control of BTM DERs report in this section for more information on the project in Placer County. Substation DR Pilots: Tier 3 Advice Letter requesting use of DR programs was approved in Resolution E-5164 on September 9. Implementation plan for use of DR programs during PSPS were created. However, no substation microgrids were operationalized during PSPS events in Q3 and October 2021 and PG&E does not anticipate any further PSPS events for the remainder of this season. Therefore, PG&E was unable to test the DR programs under this pilot.
(iii).B: Lessons Learned	None to date.
(iii).C: Quantitative Performance Metrics	Number of hybrid/clean gen locations online and operational for PSPS events in 2021. Hybrid Temporary Generation Pilots at Distribution Microgrids: 2 Substation DR Pilots: 2
(iii).D: Quantitative Risk Reduction Benefits	No incremental wildfire risk reduction benefits beyond existing substation and distribution PSPS initiatives.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	No ignition or fault risk reductions.

**TABLE:
CLEAN GENERATION FOR PSPS
(CONTINUED)**

(iv).B: Methods to Incorporate Project Findings Into Operational Practices	At this early stage of the project, we have not yet developed significant project findings to incorporate into operational practices. The expectation is that findings generated from pursuing hybrid/clean gen pilot projects in 2022 will generate key lessons learned that will be integrated into clean gen strategy in future years.
(v).A: 'End Product' at 'Full Deployment' and Location	Full deployment of this project is non-diesel generation used to mitigate the impacts of PSPS in future wildfire seasons. Locations would be in areas affected by PSPS events.

TABLE:
HIGH IMPEDANCE FAULT DETECTION AND PROTECTION

(i).A: Project Type	New Technology and Emerging Technology
(i).B: Project Objective and Summary	To help protect customers and further reduce wildfire risk during the hot and dry season, in 2021 PG&E started adjusting the sensitivity of some of its equipment to automatically turn off power faster if the system detects a problem. These adjustments are known as Enhanced Powerline Safety Settings (EPSS) and they have proven to be effective at helping prevent potential wildfires. Although EPSS has provided a dramatic decrease in reportable ignitions when compared to the prior three-year average, PG&E is relentlessly pursuing additional solutions that would eliminate wildfire risk. One of those additional potential solutions is new or emerging technologies that complement and enhance current wildfire mitigation initiatives to detect and protect against high impedance faults in real time. High impedance faults in the distribution systems are often caused by downed or broken conductors that come in contact with a roads, trees or other vegetation that does not provide a good path to ground and the fault may not be detected by conventional protection relays. As a result of the initial findings of the EPSS deployment, the objective of this new High Impedance Fault Detection and Protection project is to determine if high impedance faults can be either detected and reported, or detected and proactively mitigated, with both new or emerging technologies. If so, this project aims to provide the path-to-production guidance for a potential deployment of such technologies including up to the same footprint as where EPSS is implemented in Tier 2 and 3 HFTDs, High Fire Risk Areas, and other areas.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 11. Approach to prioritizing initiatives across territory 12. Grid design for minimizing ignition risk 14. Risk-based grid hardening and cost efficiency 15. Grid design and asset innovation

TABLE:
HIGH IMPEDANCE FAULT DETECTION AND PROTECTION
(CONTINUED)

(ii).A: Project Phase	Initiation
(ii).B: Project Status	The project team is reviewing commercially available and emerging technologies that may provide additional high impedance fault protection.
(ii).C: Project Location	Initial testing in Contra Costa county with field trials to be determined in Tier 2 and Tier 3 HFTDs.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 No results to date.
(iii).B: Lessons Learned	None at this time
(iii).C: Quantitative Performance Metrics	Detection of, or proactive mitigation of, high impedance faults currently not being addressed by EPSS Target: ≥ 75% Actual Results: Not available at this time. False positive rate Target: ≤ 10% Actual Results: Not available at this time. False negative rate Target: ≤ 5% Actual Results: Not available at this time. Protection availability/uptime (excluding external operations constraints) Target: ≥ 99% Actual Results: Not available at this time.
(iii).D: Quantitative Risk Reduction Benefits	The benefits have not been calculated for this project as it has just started and is in the Initiation phase.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	None so far.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	None available.
(v).A: 'End Product' at 'Full Deployment' and Location	If one or more of the technologies are proven to be effective at further reducing wildfire risk as well as meet operational readiness criteria for integration into PG&E's system, the end product could potentially be deployment including up to the same footprint as where EPSS is implemented in Tier 2 and 3 HFTDs, High Fire Risk Areas, and other areas. In addition, the end product would include initial and periodic training for field personnel who would interact with the system, distribution operations, and distribution engineering as well as periodic testing of the equipment and associated systems to verify reliability and sensitivity and to adjust and make operational improvements as needed.

Program Area: **Asset Management and Inspections – New or Emerging Technologies**

PG&E is developing new inspection tools and methods to quickly identify issues and proactively manage asset and system maintenance. This in turn reduces the risk of asset failure and potential impacts on our customers. PG&E is leveraging existing technologies, including remote sensing technologies such as Light Detection and Ranging (LiDAR) data and drone imagery capture,[2] to accurately identify risks, including encroachment clearance and vegetation health. Combined with machine learning software, remote sensing data are being evaluated to identify dead or dying trees that could pose wildfire hazards or contribute to a wires-down situation. Mitigations leveraging new or untested technologies include the following:

TABLE:
ENHANCED ASSET INSPECTIONS – DRONE/AI (SHERLOCK SUITE)

(i).A: Project Type	New Technology (Not Widely Commercialized)
(i).B: Project Objective and Summary	In 2019, PG&E collected more than 2.5 million high -resolution images (up to 100 megapixel) of our Electric Transmission assets through drones, helicopters, and other means of data capture as part of our Wildfire Safety Inspection Program, and has collected an additional 2.5 million images in 2020 as a part of the aerial inspection program. This imagery, when labeled appropriately, can be used to train computer vision models to identify specific components, and in some cases, evaluate the condition of those components. To address this, PG&E is developing an application, Sherlock, to bolster its data visualization capabilities. Sherlock is a web application that allows inspectors to view photographs of assets along with associated data. Sherlock allows for remote access to data captured through drone/helicopter images and enables a review of said data to ensure that only corrected data is viewed by inspectors, reducing the time from flight to inspection. In addition, inspectors can markup issues within the inspection profile of the application, which generates the necessary documentation from the application itself, ensuring auditability and data quality. This documentation provides PG&E with increased data management, reporting, and audit capabilities.

2 Future drone technology adoptions are dependent upon Federal Aviation Administration (FAA) regulations for Line of Sight requirements. If exceptions are granted to these requirements, PG&E will have the opportunity to consider new or untested drone technology use cases such as: (i) extended line of sight operations for greater crew efficiency; (ii) autonomous flight paths to expedite drone inspections; (iii) new charging methods that leverage existing asset infrastructure to minimize charging time and increase flight time.; and (iv) new data processing techniques that minimize data hand off processes by capturing and processing data in-air, allowing for greater in-air operation.

TABLE:
ENHANCED ASSET INSPECTIONS – DRONE/AI (SHERLOCK SUITE)
(CONTINUED)

	The markups from Sherlock feed into computer vision models. Computer vision models are being trained to classify photos, identify asset components, and search for potential issues in an automated fashion. Models within the inspection flow are currently being used to flag select images (e.g., overview, right of way, asset tag) for inspectors. Inspectors can label data and provide feedback on the predictions which improves the models over time while reducing the inspection time and increasing inspection quality. Further, building and improving these models provides opportunities to use computer vision to flag images for review before humans see them, for prioritizing assets/lines for inspection, for identifying asset inventory, and as inputs to models that predict future asset failure.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset inventory and condition assessments 18. Asset inspection effectiveness 20. Quality Assurance (QA)/ Quality Control (QC) for asset management
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	The Sherlock Suite now includes six different profiles for different types of users across the aerial inspection program, in addition to a number of object detection and image classification models. Four Artificial Intelligence (AI) models are currently in production, classifying images of “standard items” to reduce overall inspection time. Additionally, seven manual processes have been completely automated since the beginning of this project, and the teams are working to further automate manual steps so that inspectors can focus on looking for potential issues on assets.
(ii).C: Project Location	Systemwide Applications
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Continued work on the new post-inspection QC profile to reduce manual effort. Continued work on the new Imagery QA profile for data quality and workflow improvements. Started work on the 2022 Inspection forms for all Transmission structure types. Improvements were made to security and stability of the application and underlying data pipelines and processes. Usability improvements were made to the map functionality to help inspectors orient themselves around a structure. Introduced the ability to turn on and off particular predictions to particular users, so as to ensure a safe roll-out of new models to the Inspector profile. Q2 2021 Inspection forms for all Transmission structure types, multi-pole

	structures, telecom, and switches are now available within Sherlock, directly connecting to the system of record, and generating a PDF record on write. Woodpecker damage, C-hook wear detection, and bird nest detection models available in Sherlock to flag images where these are potentially occurring. Woodpecker damage and bird nest models now run at scale against historical imagery. Improvements to the Imagery QA profile to improve data quality and ease of use. Started work on improved/re-designed post-inspection QC profile and pre-inspection Imagery QA profile to reduce manual support time and increase effectiveness of reviews. Q1 2021 Inspection forms (checklists) for wood and steel structures available for inspectors within Sherlock, directly connecting to SAP (system of record), and generating PDF record on write. Adjustments to mode of display for predictions (i.e., different visual indicators). Ability to add new AI models to detect potential failures to the pre-inspection QA (Imagery QA) profile in Sherlock. Improved data load processes to bring data into Sherlock, for inspections. Insulator attributes detected at scale against a subset of 2020 aerial images, to assist in risk assessment of Tier 2 & 3 HFTDs. Q4 2020 Ability for post inspection QC with automated tracking within Sherlock Inspection form built within Sherlock, writing to system of record directly Bird nests flagged for inspectors using AI Ability to add new AI models to detect potential failures to the inspector profile Ability to run AI models at scale against millions of images in a cost- effective manner Ability for pre-inspection QA to occur within Sherlock Development of insulator detection, damaged cross-arm detection AI models

	Q3 2020 Ability to view completed inspections and potential emergency tags in the post-Inspection quality check profile Line level reporting and prioritization. Standardization of items predictions (level 1 automation). Development of multi component detection capabilities. Development of bird nest detection. Development of C-hook wear classification. Q2 2020 The following items were delivered: Remote image load (cloud to cloud). Image quality assurance capabilities. Near real-time tracking of remote inspections within Sherlock. Created a model to classify images of the top of a structure. Improved data pipeline, and improved application security. C-hook detection capabilities.
(iii).B: Lessons Learned	Research shows that introducing AI can affect behavior. For example, introducing automation, if not done carefully, can lead to human error due to fatigue or complacency. We are consistently measuring behavior to ensure safety of the inspection processes. As a result of this learning, we are starting our AI deployments with standard items, such as images of asset tags, overview image, access path, etc. before deploying failure detection models into production.
(iii).C: Quantitative Performance Metrics	Percentage (%) reduction in time from imagery capture to the inspection start time (as compared with our 2019 performance) Target: ≥ 50% Actual Results: 50.42% reduction Percentage (%) reduction in imagery inspection time (as compared with our 2019 performance) Target: ≥ 25% Actual Results: Inspection time has increased by 47.5% though this was expected due to the inclusion of the detailed inspection questionnaire within Sherlock in 2021, to ensure higher quality data capture. The 2021 performance will be considered the new baseline moving forward. Rate of upgrades/downgrades of findings between the initial inspector and the quality control reviewer. Target: Non-zero. This metric will set a baseline to be used to measure inspection quality improvements over time. Any improvement in inspection quality is beneficial to wildfire risk reduction. Actual Results: Not available at this time.

TABLE:
ENHANCED ASSET INSPECTIONS – DRONE/AI (SHERLOCK SUITE)
(CONTINUED)

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 2,034 Estimated RSE at Full Deployment: 48 Risk Drivers: Equipment Failure Deployment Scope Assumption: PG&E Transmission System-wide This analytics project assumes the ability to assess component condition through AI algorithms and user input. The risk mitigation potential is driven by the ability of PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	This technology is already in use by remote inspectors. Models within the inspection flow are currently being used to flag select images (e.g., overview, right of way, asset tag) for inspectors, to help focus inspection efforts on potential ignition risks.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	See reporting input (iv).A.
(v).A: 'End Product' at 'Full Deployment' and Location	Sherlock is in production and being used by different user groups across the transmission aerial inspection process. We continue to release new features on a regular basis. Future state developments include additional remote inspection processes for transmission, distribution, and substation. Potential capabilities to further enable inspectors, supervisors include: (i) data and imagery quality checks and assurance, (ii) data and imagery quality assurance, and (iii) AI enabled search functionalities. Advanced deployments of computer vision models could allow auto-filling inspection forms, automatic flagging of asset issues, and flagging of image quality issues. Additionally, instrumentation to measure inspection quality throughout the process, as well as writing back to source systems (e.g., SAP, Geographic Information System (GIS)), may be considered.

TABLE:
BELOW-GROUND INSPECTION OF STEEL STRUCTURES
(STEEL TRANSMISSION STRUCTURE CORROSION ASSESSMENT AND MITIGATION PILOT)

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	PG&E implemented a pilot that inspected steel assets below groundline to detect steel corrosion and concrete degradation that may have compromised structural integrity, with the goal of reducing risk of transmission steel structure failure. To inspect below ground, the foundations/footings of steel towers and poles were excavated and evaluated for structural integrity, including measuring steel member material section loss and collecting environmental and soil data (soil resistivity, pH, structure to soil potential/DC voltage, reduction-oxidation reaction). Repairs and mitigations were then prioritized, based on the field evaluations and soil samples, in combination with other evaluations of tower/structure and overhead assets.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset inventory and condition assessments
(ii).A: Project Phase	Closeout
(ii).B: Project Status	1010 structures have been selected and finalized for inspections and consideration for cathodic protection. Preparing RFPs for 2022 work support.
(ii).C: Project Location	Approximately 1000 locations throughout the PG&E service territory, including in HFTDs.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 This project is in Closeout. The analysis from this project has informed the follow-on Cathodic Protection Program. Q2 2021 Engineering report with the structure inspection data has been received and reviewed with further analysis ongoing by data scientists. Preliminary analysis indicates targeted inspections are advised among direct grillage steel foundations and in regions/locations with evidence of greater corrosion. Q1 2021 Project crews in the field inspected ~1000 structures. Pictures, field measurements, and inspector comments have been gathered and are currently undergoing desktop analysis.

	Preliminary results and field data are currently being incorporated into other established models that contribute to wildfire safety such as the Operability Assessment. Q4 2020/Q3 2020 Project scope finalized Structures for testing identified Field operations processes and methods for project implementation documented. Prior Results Data analysis and project definition. Structure selection and reaching out to contractors.
(iii).B: Lessons Learned	Verified efficacy of concrete as a subgrade corrosion deterrent of buried steel. Environmental factors of the various PG&E service regions produce varying levels of sub-grade corrosion and should inform inspection priority.
(iii).C: Quantitative Performance Metrics	Ability to apply analytics from data collected for insights on steel section loss based on age, geography, and operational conditions to inform the design of cathodic protection preventative maintenance programs. Target: Pass Actual Results: Pass Ability to validate whether a correlation exists between atmospheric corrosion (as seen on steel members above ground) and subsurface corrosion. Target: Pass Actual Results: We have validated that there is no correlation between atmospheric corrosion and subsurface corrosion.
(iii).D: Quantitative Risk Reduction Benefits	Quantitative Risk Reduction Benefits cannot be calculated for this project due to the lack of historical ignition data for steel structures in PG&E's Enterprise Risk Model wildfire risk assessment and bowtie analysis.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The findings of this project have informed the Cathodic Protection Program.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Data integrated into asset management data models to help prioritize asset maintenance practices based on risk assessments. The project findings, including where cathodic protection would be most impactful, are an input to the Cathodic Protection Program.
(v).A: 'End Product' at 'Full Deployment' and Location	Broader implementation of below ground inspection of steel structures.

TABLE:
BELOW-GROUND INSPECTION OF STEEL STRUCTURES
(STEEL TRANSMISSION STRUCTURE CORROSION ASSESSMENT AND MITIGATION PILOT)
(CONTINUED)

	Data integrated into asset management data models to help prioritize asset maintenance practices based on risk assessments. A decision to deploy cathodic protection to better protect from corrosion impact.

TABLE:
EPIC 3.41: DRONE ENABLEMENT

(i).A: Project Type	New Technology (Not Widely Commercialized)
(i).B: Project Objective and Summary	This project proposes to test the following two hypotheses: Transmission Line & Substation Inspections: Automated and Beyond Visual Line of Sight (BVLOS) drone flight operations can offer a more accurate, safe and more efficient alternative to Transmission Line & Substation asset inspection than today's manual drone operations. Distribution Alert Verification: Automated and BVLOS drone operations can provide a fast, safe and effective solution for field-validating the range of alerts that will be produced through the predictive sensors that are planned to be deployed across the distribution system.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset Inventory and condition assessments 17. Asset inspection cycle 18. Asset inspection effectiveness 19. Asset maintenance and repair
(ii).A: Project Phase	Design/Engineer
(ii).B: Project Status	The project was officially launched in August 2020. The internal project team has been staffed, and the team has partnered with an external expert of drone technology and the Federal Aviation Authority (FAA) regulatory requirements and process to provide critical support during the Design/Engineering phase of the project. The team has documented the details of each planned use case, developed a preliminary CONOPS document and then translated the CONOPS into technical requirements, and conducted an RFP to selecta drone vendor partner. The team has also conducted preliminary coordination with the FAA.
(ii).C: Project Location	Project location is TBD. The team has conducted preliminary assessment of site selection parameters that will both support the project's objectives and meet FAA requirements for BVLOS operations. Sites will be selected in partnership with drone vendor partners.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Evaluated and down-selected drone vendors based on the RFP scorecard. Developed milestone-based statements of work with each of the selected vendors in preparation for contract execution. Q2 2021 Completed development of RFP package for primary drone vendor contract.

TABLE:
EPIC 3.41: DRONE ENABLEMENT
(CONTINUED)

	Launched RFP, completed question & response phase and received bidder proposals.

TABLE:
EPIC 3.41: DRONE ENABLEMENT
(CONTINUED)

	Q1 2021 Conducted preliminary conversations with the FAA to socialize our concept and understand/address any preliminary concerns. Finalized the set of technical requirements for the RFP Developed plan for RFP, began compiling list of invitees, and began developing package RFP documents. Q4 2020 Expert drone consultant onboarded. Project schedule established. Use case questionnaire form completed (transmission, substation & distribution) for CONOPS development. Slide deck for discussion with FAA drafted. Initial RFP invitee list drafted. Q3 2020 Business Plan approved.
(iii).B: Lessons Learned	None to date.
(iii).C: Quantitative Performance Metrics	For transmission & substation inspections: Percentage (%) reduction in time of automated data capture compared to equivalent manual data capture Target: 20% Actual Results: TBD. Results will be available once the field demonstrations have been conducted. Percentage (%) of automated operations without errors or gaps in data capture that would require repeat operations Target: 99% Actual Results: TBD. Results will be available once the field demonstrations have been conducted. For distribution alert verifications: Percentage (%) reduction in duration of patrols executed in response to automated alerts from sensors installed on the distribution system, compared to equivalent patrols performed on foot, by truck or by helicopter, or some combination thereof Target: 20% Actual Results: TBD. Results will be available once the field demonstrations have been conducted.

TABLE:
EPIC 3.41: DRONE ENABLEMENT
(CONTINUED)

(iii).D: Quantitative Risk Reduction Benefits	This project has two use-cases where risk reduction scores are not applicable because the risk reduction opportunities are tied to existing processes and new project applications. For transmission and substation inspections, this project will collect images more efficiently and inspectors will continue to use Enhanced Asset Inspections—Drone/AI (Sherlock Suite) to perform virtual inspections. The distribution use-case will leverage drone operations to efficiently field-validate alerts produced by predictive sensors. Risk reduction benefits of this project are tied to and are accounted for in specific Asset Health and Performance Center projects and their associated sensors or analytics; the benefitting projects include Line Sensors, EPIC 3.13: Transformer Monitoring via FAN, EPIC 3.20: Maintenance Analytics, EPIC 3.43: Momentary Outage Information, EFD and Distribution Fault Anticipation.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	TBD
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	TBD
(v).A: 'End Product' at 'Full Deployment' and Location	Transmission & Substation Inspections: Scaled up version of the solution at the end of the EPIC project to extend to the broader set of Transmission lines and substations in HFTDs. Ability to collect imagery data utilizing an autonomous Unmanned Aerial Vehicle for detailed inspections on all assets within scope. Distribution Alert Verification: Scaled up version of the solution at the end of the EPIC project to extend to the broader set of distribution assets in HFTDs. Improved integration between sensor alert system and drone system, with automated sharing of geospatially referenced alerts. Command and control application to monitor and track health and status of the fleet of drones and suggest which drone to deploy for inspection or field validation based on location, range, charge level, weather and other relevant factors. Potentially also a consolidated physical mission control center within a DCC for operational management and situational awareness of the fleet of drones. Interfaces between the drone system and additional field sensor alert systems would be created (beyond the specific field sensors being used in this project; for instance, some combination of sensors from the Line Sensor, Enhanced Fault Detection, or DFA projects).

TABLE:
EPIC 3.46: ADVANCED ELECTRIC INSPECTION TOOLS – WOOD POLES

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	This project seeks to develop a new, non-destructive testing method to analyze the condition of wood poles. The proposed non-destructive method is radiographic testing (RT) in which radiation is passed through an object and the material density and thickness attenuate the radiation and reveals the internal composition without the need for intrusive testing. Since traditional intrusive testing is limited to only evaluating a few sections of the pole, RT may provide an opportunity to perform a more complete analysis of the overall health and condition of existing wood poles. In addition, RT can also assist in the many areas of the wood pole which are not commonly inspected such as center-bored wood streetlight poles and poles with risers or utility equipment. The additional information provided by RT may enable more informed, data-driven decisions and further improve the forecasting of wood pole replacements and performing of wood pole repairs. The main objective is to reduce the occurrence of failed wood poles which directly mitigates the potential for fire ignition events.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening 12. Grid design for minimizing ignition risk D. Asset management and inspections 16. Asset inventory and condition assessments 17. Asset inspection cycle 18. Asset inspection effectiveness
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	Onboarding the project team and developing a detailed project plan.
(ii).C: Project Location	Advanced Technology Services (ATS) center in Contra Costa county.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Initial communications with the digital radiography manufacturer for feedback on detailed plan and availability of equipment
(iii).B: Lessons Learned	N/A
(iii).C: Quantitative Performance Metrics	Limit of unacceptable level of decay or cracking (determined by comparing conventional RT data in conjunction with destructive testing). Target: Not yet determined. Actual Results: Not available at this time.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 1 Estimated RSE at Full Deployment: 1 Risk Drivers: Equipment Failure – Pole damage or failure

TABLE:
EPIC 3.46: ADVANCED ELECTRIC INSPECTION TOOLS – WOOD POLES
(CONTINUED)

	Deployment Scope Assumption: Distribution poles system-wide Risk mitigation potential comes from the reduction of ignition events by reducing wood pole failure. Currently, wood pole inspection consists of a visual, sound (hammer test), and intrusive (bore and probe test) inspection aligned with General Order 165. To further reduce the need of performing intrusive inspection by drilling and to gain a better understanding of the wood pole health, nondestructive testing can be utilized via radiographic testing (RT). RT can assist in the many areas of the wood pole commonly not inspected such as center-bored wood streetlight poles and poles with risers or utility equipment. Such nondestructive testing may provide an opportunity to better analyze the overall health and condition of wood poles which may further improve the forecasting of wood pole replacements and making data driven decisions for wood pole repairs.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	None available at this time.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	None available at this time.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	Production-ready digital real-time RT unit(s) as well as appropriate mandatory training and qualification available throughout the service territory.

Program Area: **Vegetation Management and Inspections—New or Emerging Technologies**

PG&E is using a variety of technologies to improve our vegetation management (VM) practices. For instance, physical ground inspections are being augmented by the capture of LiDAR and related, remote sensing, data that can be thoroughly and consistently analyzed to take measurements, reveal patterns and identify risks. VM has benefited from improved intelligence regarding vegetation density and can leverage this data to strategically deploy resources where vegetation is near electrical assets. Mitigations leveraging new or emerging technologies include the following:

TABLE:
MOBILE LiDAR FOR VEGETATION MANAGEMENT

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	This project sought to validate that high-resolution data captured with vehicle and backpack-mounted LiDAR and imagery units could help reduce fire risk and improve compliance of PG&E's VM process. The 2020 Pilot focused on one 84-mile circuit to evaluate the benefits and risk spend efficiency of LiDAR to the Planning, Pre-Inspection, Work Verification, and Documentation phases of the end-to-end VM radial clearing process. The 2021 Pilot was focused on operationalizing vehicle-based LIDAR data collection and analysis on an individual VM job basis following Work Verification.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	E. VM and inspections: 22. Vegetation inspection cycle 23. Vegetation inspection effectiveness 24. Vegetation grow-in mitigation 26. QA/QC for VM
(ii).A: Project Phase	2019 Pilot: Closeout 2020 Pilot: Closeout 2021 Pilot: Closeout
(ii).B: Project Status	The 2021 Pilot has entered the Closeout phase and the overall Mobile LiDAR program has transitioned to full operational status.
(ii).C: Project Location	2019 Pilot: ~18K miles driven in Tier 2 & 3 HFTDs. 2020 Pilot: 84 driven miles along a circuit in Placer and Nevada counties. 2021 Pilot: ~27 VM Projects across HFTDs.

TABLE:
MOBILE LiDAR FOR VEGETATION MANAGEMENT
(CONTINUED)

(iii).A: Results to Date	Q3 AND OCTOBER 2021 The 2021 Pilot entered the Closeout phase at the end of Q2 2021 thus there are no further results to report for Q3 and October 2021. Q2 2021 The first VM job to be evaluated as part of this Mobile LiDAR project was scanned and data from the vendor was received. Q1 2021 Identified the 856 Circuits that are in HFTDs and are eligible for Mobile LIDAR scanning. Identified the 484 VM Projects that do not map directly to a PG&E circuit and began additional required mapping. Q3 2020 / Q4 2020 Collected and analyzed Pre- and Post-Work measurements. Performed field check of preliminary 2019 radial clearing results, and assigning toward remediation when appropriate. Determined the percent of circuits measurable from a road with sufficient quality in Tier 2 & 3 HFTDs. Prior Results See (iii).B Lessons Learned below.
(iii).B: Lessons Learned	From the 2019 Pilot PG&E learned that Mobile LiDAR is capable of measuring radial clearances and clearances to sky, and: Initiated operationalization of results into VM processes. Derived cost and data analysis cycle time performance measures for both vehicle and backpack-mounted sensors. To reduce false positives, point cloud analysis teams need an accurate inventory of primary conductor assets (e.g., the teams need to be able to exclude secondary conductors and telecommunications cables). Mobile LiDAR can help improve asset locational data accuracy. Field teams could benefit from integrated access to geospatial data in their mobile applications. No public receptivity issues found with the car-based mobile LiDAR inspections. Post-work scan results can support work verification and cycle time planning. From the 2020 Pilot, PG&E learned that the LiDAR data acquisition and processing can occur within 27 days, a period sufficient for VM operational workflow cycle times.

TABLE:
MOBILE LiDAR FOR VEGETATION MANAGEMENT
(CONTINUED)

	Vegetation detections must be delivered to Operational Personnel in a geographic, trackable map.
(iii).C: Quantitative Performance Metrics	Scan analysis cycle time Target: 27 days from scan to data delivery. Actual Results: 30 days
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 2,838 Estimated RSE at Full Deployment: 51 Risk Drivers: Vegetation Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	Mobile LIDAR scanning was performed on road-side miles of distribution line in HFTDs, following the completion of VM work verification on the line. The Mobile LIDAR identification of a radial clearance issue would be delivered to the Work Verification work flow for inspection and mitigation.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Evaluation of the stepwise integration of the methods described in (iv).A into VM operational workflows for road-side distribution corridors in HFTDs.
(v).A: 'End Product' at 'Full Deployment' and Location	Ground Based LIDAR results in two main products, the first of which is the LIDAR 3D files of our distribution lines and vegetation at the time of collection. These files are used to document compliance for later review. The second product is a geographic file of where vegetation may have radial encroachments. Through operational processes, these locations trigger a Work Verification inspection and a record of compliance or of work generated.

TABLE:
EPIC 3.47: OPERATIONAL VEGETATION MANAGEMENT EFFICIENCY THROUGH NOVEL ON-SITE EQUIPMENT

(i).A: Project Type	New Technology (Not Widely Commercialized)
(i).B: Project Objective and Summary	PG&E believes that there are opportunities to reduce cost and potentially improve environmental and safety outcomes of vegetation management through novel technology deployment. This project's objectives include completing technology demonstrations of novel wood baling and mobile torrefaction technology, both of which could improve upon wood handling metrics when deployed at scale. Wood baling is expected to reduce labor requirements and processing costs. Mobile torrefaction is a process to create valuable products from heat treating woody biomass and could eliminate disposal costs (known as "tipping fees") while having an added benefit of reducing the carbon intensity of our energy portfolio. A further objective of the project is to produce a final report that would include an economic and logistics analysis for deployment of each technology within PG&E's service territory.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	E. Vegetation management and inspections 24. Vegetation grow-in mitigation 25. Vegetation fall-in mitigation
(ii).A: Project Phase	Planning
(ii).B: Project Status	An RFP is being developed to identify and contract with potential vendors offering novel solutions.
(ii).C: Project Location	TBD
(iii).A: Results to Date	None at this time
(iii).B: Lessons Learned	None at this time
(iii).C: Quantitative Performance Metrics	Percentage cost reduced per relevant unit for given solution (i.e. per tonnage, project, or mile traveled) Target: To be determined (percentage) Actual Results: None available at this time Percentage of greenhouse emissions reduced (all sources, including but not limited to transportation) associated with processing a quantity of woody biomass with this technology as compared to standard practices. Target: TBD (percentage) Actual Results: None available at this time Percentage speed improvement associated with processing a quantity of woody biomass with this technology as compared to standard practices. Target: TBD (percentage) Actual Results: None available at this time

TABLE:
EPIC 3.47: OPERATIONAL VEGETATION MANAGEMENT EFFICIENCY THROUGH NOVEL ON-SITE EQUIPMENT
(CONTINUED)

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: Not applicable

TABLE:
EPIC 3.47: OPERATIONAL VEGETATION MANAGEMENT EFFICIENCY THROUGH NOVEL ON-SITE EQUIPMENT
(CONTINUED)

	There is no direct wildfire risk reduction for this project. The project goals are more aligned with improving metrics related to vegetation management cost effectiveness, environmental outcomes, and worker safety. Indirect wildfire risk reduction benefits may be possible in the future through increased efficiency (i.e. enabling a larger impact from the existing vegetation management funds). It is not possible to quantify such potential indirect benefits at this early stage.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	None so far as the project was just approved.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	None available at this time as the project has just been approved.
(v).A: 'End Product' at 'Full Deployment' and Location	A technology deployment throughout the portion of the service territory where deployment is justified. The strategy is to demonstrate the value of new technologies and then leverage that knowledge when negotiating future contracts with PG&E Vegetation Management vendors.

<u>Program Area</u>: Asset Analytics & Grid Monitoring – New or Emerging Technologies

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. Proactive management of asset health can reduce this risk and enhance system resiliency. PG&E is researching new or emerging technologies, such as enhanced sensor technologies that enable real-time system monitoring and situational awareness and developing analytic strategies to coordinate data received from multiple sources (e.g., SCADA, SmartMeter electric meters, primary line sensors, and emerging sensor technologies). Mitigations leveraging new or emerging technologies include the following:

TABLE:
EPIC 3.13: TRANSFORMER MONITORING VIA FIELD AREA NETWORK

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	As service transformers reach the end of their usable life or overload, they begin to heat up, leading to potential safety and asset risks. Currently, identification of transformer temperature change and potential associated risks poses challenges and requires regular checks from PG&E field teams. The EPIC 3.13: Transformer Monitoring via FAN demonstration project aims to increase the visibility of transformer health through the design and build of an overhead service transformer temperature sensor, a Temperature Alarm Device (TAD), supplemented by analytical models that analyze temperature data. The project will test the hypothesis that monitoring the external temperature of the tank of an overhead transformer can help in predicting and preventing imminent failure that could pose a wildfire ignition risk as well as impact safety and resiliency.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk D. Asset management and inspections: 19. Asset Maintenance and Repair G. Data governance: 33. Data collection and curation
(ii).A: Project Phase	Design/Engineering

TABLE:
EPIC 3.13: TRANSFORMER MONITORING VIA FIELD AREA NETWORK
(CONTINUED)

(ii).B: Project Status	The team is evaluating TAD samples and TAD costs provided by vendors, obtaining site licenses to access vendors' servers to obtain TAD data, and preparing to compare data from the TAD vendors.
(ii).C: Project Location	Initial planned locations are in the San Jose area.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Procurement of 40 sensors initiated and candidate sites reviewed for permitting and traffic considerations. Q2 2021 Received TADs from four vendors to evaluate safety and installation feasibility. Preparation underway to install a small number of TADs to catch the summer heat wave, and to inform the pending RFP for the larger acquisition of sensors. Q1 2021 Business plan approved for project initiation. TAD vendors interviewed for demonstration project. Installation locations in the San Jose area identified Installation review meetings with the construction contractor. IT cybersecurity coordination initiated. Q4 2020 Prepared business plan approved for project implementation. Identified external TAD vendors for demonstration project.
(iii).B: Lessons Learned	There is a strong preference to install the TADs with the transformer energized so as to not impact customers; however, we have learned that this is not always possible.
(iii).C: Quantitative Performance Metrics	Ability to detect an imminent failure of an overhead transformer and create an alert with an actionable amount of time within current maintenance programs to proactively replace the transformer that is degrading or near the end of its useful life. Target: Pass Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 687 Estimated RSE at Full Deployment: 98 Risk Drivers: Equipment Failure Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs

	This analytics project assumes the ability to detect issues with overhead transformers prior to failure. The risk mitigation potential is driven by the ability of PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the TAD effectively helps in the detection of imminent failure of overhead transformers, PG&E will be able to proactively replace transformers by dispatching field crews, thereby preventing failure, potential ignition risks, and associated outages.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	If the TAD technology is proven to be effective, (i) the communication system used by the TADs would need to be operationalized, (ii) the data would need to be integrated with our production databases, and (iii) the data would need to be combined with other data streams in an enterprise data analytics platform to provide a more holistic understanding of asset health.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	TADs would be installed on existing overhead transformers, prioritized first in Tier 3 HFTDs followed by Tier 2 HFTDs. Deployment in other locations will be based upon a risk analysis and subject to available funding.

TABLE:
EPIC 3.20: MAINTENANCE ANALYTICS

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	The EPIC 3.20: Data Analytics for Predictive Maintenance project aims to develop analytical models using machine learning based on existing PG&E data sets (including SmartMeter electric meter connectivity, geolocational assets, and weather data) to predict electric distribution equipment failures so that corrective action can be taken before failure occurs. The project now has 3 phases. Phase 1 aimed to predict power quality-related failures of distribution transformers based upon voltage data. Phase 2 focused on ignition risks and catastrophic failures associated with near-failure distribution transformers. Phase 3 focuses on identifying grid event behavior which may indicate vegetation contact or other intermittent faults on overhead distribution equipment.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 19. Asset maintenance and repair
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Phase 1 and phase 2 have been completed. Phase 3 is under development.
(ii).C: Project Location	The project's algorithm testing and verification is ongoing across PG&E's entire distribution service territory.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Phase 2 results are available and included in (iii) C below. For Phase 3, the team has finished a Minimum Viable Product (MVP) of the model which uses grid event data in order to predict outages on overhead distribution equipment. The model's performance on training data meets business value thresholds, and is now undergoing scheduled refinement and validation. Q2 2021 Assets such as distribution transformers and meters have been proactively replaced based on the model's recommendations (Phase 2), in doing so reducing wildfire risk and improving reliability for customers. Given the successful results of the model in Phase 2, as described in (iii).C, this phase of the project is intended to grow from an early stage demonstration project to an operational data product. Deep dive conducted with CPUC's EPIC Program staff in June during a quarterly CPUC/PG&E check-in meeting. In addition, the project was presented to Filsinger Energy (the Governor-appointed Operational Observer).

TABLE:
EPIC 3.20: MAINTENANCE ANALYTICS
(CONTINUED)

	Q1 2021

	Additional use cases for incipient transformer failures (Phase 2) and intermittent faults with overhead equipment (Phase 3) have been approved. Developed Minimum Viable Product (MVP) of Phase 2 model for predicting distribution transformer failures. The model learns from past failures that resulted in catastrophic and ignition events. Q4 2020 Failure model MVP is in progress Developed scope of the Phase 2 and Phase 3 use cases. Q3 2020 Field validation of predicted failing transformers due to power quality (in progress) Through iterative development, the best model has improved and now has 98 percent precision for predicted failures. Q2 2020 Added heuristic to identify fuse failures. The best prediction model had 87 percent precision when making predictions on a set of 300 failures.
(iii).B: Lessons Learned	Occurrences of poor data quality, including poor data quality of historical asset data, must be addressed to ensure prediction accuracy. Resolving data quality as close to the source as possible helps to ensure that data cleansing activities are not being duplicated by independent downstream processes. Similar to how risk calculations include both the expected consequence of the event, as well as the probability of the event occurring, benefits calculations should include both the expected business value as well as the probability of that value being realized. Critical elements of this probability include data fidelity, the existence of an established business process, and the availability of change management support. While the model development is still in progress, it has been demonstrated that using aggregated SmartMeter data allows for the identification of transformers that are performing outside of normal operating parameters. Working on a centralized data platform (i.e. Foundry) now allows for productivity acceleration in terms of access to data including historical asset data, scaling, and a path to production.
(iii).C: Quantitative Performance Metrics	Percentage (%) of predictions that upon review warrant field investigation. Target: ≥50% Actual Results: Over 200 desktop engineering reviews of Phase 2 predications have been conducted, from which ~70 percent were confirmed to be relevant transformer anomalies and were either flagged

	for field investigation or sent to other teams to address the issues. Additional anomalies, that do not represent an imminent wildfire risk have also been identified accounting for an additional ~9 percent. Number of assets that are proactively repaired or replaced Target: Non-zero Actual Results: Based on the transformers that were flagged directly for field investigation, over 30 transformers or related assets have been proactively repaired or replaced. The field crews confirmed seeing anomalies in these assets that indicated incipient failure. Moreover, 15 of these assets are in Tier 2 & 3 HFTDs.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 4,845 (across all phases) Estimated RSE at Full Deployment: 744 Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs This analytics project assumes the ability to detect issues with distribution transformers prior to failure. The risk mitigation potential is driven by the ability of PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the model predicts a failing asset, a Troubleman could be alerted based on model findings and dispatched to inspect the asset and perform maintenance or replace the asset as needed.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The analytics model that was developed in Phase 2 has been integrated into the Asset Health and Performance Center operational process for monitoring distribution transformers assets. The model uses machine learning to provide weekly probability of failure. When the probability exceeds a threshold, the asset will be flagged for review. Depending on findings of the review, PG&E may dispatch crews to inspect and then perform maintenance on, or replace, the asset as needed.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product will be an analytical model fully integrated into the Asset Health and Performance Center's distribution grid monitoring and analytics platform. This would include integration of workflows to proactively address and track outcomes from issues identified by the analytic model. The model will enable better-informed decisions made by the Power Quality and Asset Health & Performance Center teams throughout the entire service territory.

TABLE:
EPIC 3.32: SYSTEM HARMONICS FOR POWER QUALITY INVESTIGATION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	The EPIC 3.32: System Harmonics for Power Quality Investigation demonstration project explores the use of next generation metering technology harmonics data to help automate the detection, investigation, and resolution of harmonics issues. Excessive harmonics have been shown to reduce utility equipment life, can cause premature equipment failure due to the potential to overheat, and can interfere with the operation of protection devices. Harmonics data from next generation metering technology can enable power quality engineers to monitor harmonics levels on the circuits and proactively address harmonics issues before they create a negative impact on PG&E and customers' equipment, mitigating the chances of equipment failure to have adverse effects or safety impacts.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 14. Risk-based grid hardening and cost efficiency
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	The project team is currently working with Information Technology (IT) to complete both the build of the backbone meter data pipeline and the development of the Sprints, Analytics User Cases, and User Interface Visualization, enabling data analysis, algorithm development, and display of results.
(ii).C: Project Location	Three phase agricultural customers in the Central Valley region as well as three phase agricultural or commercial/industrial customers with DERs or PV generation (locations are systemwide).
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Completed the build of the data collection and analytics server for the meter data. Completed the Staging Phase. Q2 2021 Completed installation of 180 next generation meters (this is the extent of the pilot meter population). Completed IT infrastructure required to communicate with the meters and acquire the harmonics data from the meters. Q1 2021 Identified 180 meter install locations. Completed inspection and wiring of 88 meter locations.

	Q4 2020 Issued PO to meter hardware vendor. Kick-off project with IT. Q3 2020 Finalized field installation plan including meter installation locations. Completed RFP and selected meter hardware that met the requirements to provide the necessary harmonics data.
(iii).B: Lessons Learned	Meter procurement took longer than expected due to contractual issues between the vendor and PG&E legal teams. We should connect the vendor legal team and PG&E teams together sooner next time. PG&E awarded the contract to the vendor’s distributor instead. Some of the predetermined meter locations were inspected and found infeasible by Field Metering. So, we had to revise the list of meter locations based on Field Metering feedback, we could benefit engaging Field Metering earlier during the process of identifying meter locations for the project.
(iii).C: Quantitative Performance Metrics	Percentage (%) availability of harmonics data from installed meters. Target: ≥ 90% Actual Results: To be provided as available from assessment data. Number (#) of hours to notification after harmonics levels meet analytical criteria. Target: ≤48 hours Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 1,653 Estimated RSE at Full Deployment: 489 Risk Drivers: Equipment Failure Deployment Scope Assumption: 12,728 miles of distribution lines in Tier 2 & 3 HFTDs, and 32,423 miles of distribution lines in Non-HFTDs This analytics project assumes the ability to detect harmonics that lead to failure of capacitor banks, fuses, and transformers. The risk mitigation potential is driven by the ability for PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.

TABLE:
EPIC 3.32: SYSTEM HARMONICS FOR POWER QUALITY INVESTIGATION
(CONTINUED)

(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The plan is to validate locations with high levels of harmonics and determine if there is a harmonics-associated ignition risk to the transformers, cap banks, and fuses in the location. If a suspected ignition risk is found, the plan is to take action using existing operational processes.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The plan is to use next generation metering technology to monitor and collect harmonics data on our electric distribution system for operationalizing harmonics-associated risk reductions.
(v).A: 'End Product' at'Full Deployment' and Location	The end product would include the installation of a three phase next generation meters at approximately 3,000 customers throughout the service territory and an analytics tool with the ability to monitor for, and enable proactive mitigation of, harmonics-related issues that could lead to failures and associated wildfire risk.

TABLE:
SENSOR IQ

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	Sensor IQ is a SmartMeter software application that enables SmartMeter electric meters to collect data at a higher frequency and deliver alarms such as high/low voltage outside configurable thresholds without disruption to normal billing data collection. This pilot enables and collects high frequency SmartMeter data; analytics using this data will only be performed through other projects. PG&E has a license to pilot Sensor IQ through May 2022 and will collect voltage, current, and power factor data every five minutes from meters included in this pilot. The purpose of this Sensor IQ project is to collect the needed data to be analyzed through other exploratory use cases to evaluate if the high frequency data supports 1) improved meter phase identification, as this information is needed by the EPIC 3.15: Proactive Wires Down Mitigation Demonstration Project (REFCL), which requires feeder phasing to determine the line-earth capacitive imbalance; and 2) EPIC 3.43: Momentary Outage Information, which seeks to use near real time meter data, including the data provided through Sensor IQ, to develop algorithms that can potentially identify the sources of momentary outages or other anomalies to create predictive maintenance strategies and processes; 3) other predictive grid monitoring and maintenance approaches for potential wildfire risk reduction methods through incipient fault detection as well as improvement of the ability to find faults in wires-down analytics.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 14. Risk-based grid hardening and cost efficiency
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Project is in a validation phase scheduled to complete by the end of Q1 2022.
(ii).C: Project Location	~500K SmartMeter electric meters located in Tier 2 & Tier 3 HFTDs.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Work is ongoing on the analytics for the high frequency data being collected on the 500K+ meters in Tier 2 & Tier 3 HFTDs. Q2 2021 Meter profile deployment completed to 500K meters with data collection ongoing. Q1 2021 Meter profile deployment completed to 500 additional meters, bringing total of Sensor IQ-enabled meters to 1,500.

TABLE:
SENSOR IQ
(CONTINUED)

	Network impact monitoring tools now used to assess network impact during rollout. Q3 2020/Q4 2020 Data collection profiles, alarm thresholds and configurations have been developed for various meter types. Sensor IQ has been deployed in the meter test environment to validate developed Data Collection Profiles. Production meter deployment started
(iii).B: Lessons Learned	High frequency SmartMeter data alone was not enough to detect issues accurately. Analytics support is necessary to make the data provided by this project useful. Therefore, PG&E plans to direct this project's data, when available, into the EPIC 3.20: Maintenance Analytics, and EPIC 3.43: Momentary Outage Information projects to use their analytical components for meters in Tier 2 & 3 HFTDs. See the EPIC 3.20 and 3.43 project descriptions in this report for more information.
(iii).C: Quantitative Performance Metrics	Percentage (%) of high frequency interval data and events from the meters collected and made available for use within two hours under non-event conditions (e.g. no outage). Target: ≥95% Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Sensor IQ is a foundational data collection project without its own Quantitative Risk Reduction Benefits. The EPIC 3.15 Proactive Wires Down Mitigation Demonstration Project (REFCL), EPIC 3.20 Maintenance Analytics, and EPIC 3.43 Momentary Outage Information projects rely on data from this Sensor IQ project, and each have their own Quantitative Risk Reduction Benefits as provided herein.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If this project is found to benefit early identification of wildfire risks, the analytics developed in companion projects can be automated and integrated into existing preventative monitoring schemes.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Automate the ingestion of Sensor IQ data into a data platform and apply analytical methods to assess events for indications of incipient conditions. Integrate data and analytics into existing or newly developed workflows for detection and resolution of incipient grid conditions that could create wildfire risk. Move the project to a production IT environment. The software contract for this pilot would be extended for deployment and converted to a full license.
(v).A: 'End Product' at 'Full Deployment' and Location	If effective, this product would be deployed in all circuits in Tier 2 & 3 HFTDs and integrated into standard distribution operation functions. It could also be extended to systemwide deployment to all compatible SmartMeter electric meters with an additional per-meter software license.

TABLE:
EPIC 3.43: MOMENTARY OUTAGE INFORMATION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	PG&E has deployed over 5 million SmartMeters that provide alarm traps related to the meter’s health and status during abnormal system conditions, such as outages, broad detection of sag and swell events, voltage deviations, intermittent power “blinks”, or other anomalies as reported by the SmartMeter technology. This project proposes to leverage SmartMeter data through Sensor IQ (also in this section) on about 500K meters for more granular and real-time data streams that include high frequency voltage, current, power factor, and temperature, and real time notifications voltage variations or temperature alarms that can be used to develop algorithms that can potentially identify the sources of momentary outages/voltage excursions to create predictive maintenance strategies and processes. An objective is to determine if momentary electrical events (sometimes referred to as “blinks” akin to a light flickering) and other electrical event trap alarms available from PG&E’s fleet of over 5 million SmartMeters correlate and can be used to identify specific equipment shortcomings such as transformer failure, cracked insulator, loose neutrals, and/or vegetation contact, thereby leading to preventative maintenance practices that could also help reduce wildfire ignition risk. A second part of the project is underway that adds field insight from two additional sources of information: a new generation smart meter/grid edge sensor, and a Behind The Meter (BTM) electrical condition detection sensor. The use of a new generation of meter potentially offers measurement and analysis of various primary and secondary issues including but not necessarily limited to loose neutrals, failing service transformers, failing splices, and vegetation contact, while the BTM electrical condition detection sensor provides an independent view of similar potential issues, but from the customer side of the meter. These BTM electrical condition detection sensors are owned by a third-party though PG&E will receive access to the data as part of this project.
(i).E: UWMMM Categories & Capabilities Potentially Impacted	D. Asset management and inspections 16. Asset inventory and condition assessments
(ii).A: Project Phase	Design/Engineer
(ii).B: Project Status	The first part of the project has initiated analytics development using the now-available Sensor IQ data from ~500K meters in Tier 2 & Tier 3 HFTDs. The second part of the project (using the new generation meter and the BTM electrical condition detection sensor) is being initiated. Vendors have been selected and contracts with both vendors have been executed. The work evaluating the BTM electrical condition detection sensor is showing promise for detecting loose neutrals. We are awaiting delivery of 440 next generation meters in Q1 2022.

TABLE:
EPIC 3.43: MOMENTARY OUTAGE INFORMATION
(CONTINUED)

(ii).C: Project Location	The Sensor IQ-based analysis is applicable to the entire PG&E electric distribution service territory served by SmartMeters but is now focused on meters in Tier 2 & Tier 3 HFTDs. The new generation meters are being installed on a feeder in Napa County. The BTM electrical condition detection sensors have third-party ownership and PG&E does not control where they are installed. They are actually installed throughout PG&E's service territory through PG&E is focusing analysis efforts on Tier 2 & Tier 3 HFTDs.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Developed machine learning model features to predict transformer failures using Sensor IQ's 5-minute smart meter data. Researched and analyzed historical Loose Neutral events to correlate them with events obtained from the BTM electrical condition detection sensor technology. Executed contract for next generation meter sensor technology. Q2 2021 The internal change request formalizing the addition of the two additional sensor technologies to the scope of the demonstration has been approved. Connection established from Sensor IQ data source into Foundry. Q1 2021 Developed a project change request formalizing the addition of the two additional sensor technologies to the scope of the demonstration. Q4 2020 For the first part of the project: Defined data points and data frequency requirements to perform analytics work to potentially identify equipment failures for enhanced preventative maintenance practices that focus on replacement before failure. Developed IT framework (solutions blueprint) to ingest and provide data for analytics work. For the second part of the project: Vendors and installation locations have been selected. Two additional potentially useful data sources have been identified: new generation SmartMeter technology, and in-home electrical fire sensing. Analysis of project scope and cost changes to accommodate these data sources has been initiated.
(iii).B: Lessons Learned	None to date

TABLE:
EPIC 3.43: MOMENTARY OUTAGE INFORMATION
(CONTINUED)

(iii).C: Quantitative Performance Metrics	Percentage (%) of predictions that upon review warrant field investigation. Target: ≥50% Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score at Full Deployment: 2,231 Estimated RSE at Full Deployment: 193 Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs This analytics project assumes the ability to detect issues with conductors, insulators, splice/clamp/connectors, transformers, and vegetation failures prior to failure. The risk mitigation potential is driven by the ability for PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs. The scores above are estimates considering a potential ten year deployment of the technology as defined and may be useful for comparing the projects in this section amongst themselves, though are not directly comparable to the risk scores that are provided for the incremental deployments of some of these same technologies as included in Section 7.3.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	None to date.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	For the first part of the project: If the predictive models using Sensor IQ data are found to be successful, the next phase of development would be to move the analytical model to full production. Operational actions potentially include more precisely targeted PSPS events, more precisely targeted VM, optimized truck rolls, or temporarily reconfiguring distribution system topology. Additionally, improved maintenance planning and optimized capital allocations are likely benefits of more precisely understanding equipment condition. For the second part of the project: If the technologies (the next generation meter and the BTM electrical condition detection sensor) are found to be successful in identifying incipient issues the more effective version will be assessed for larger deployment.
(v).A: 'End Product' at 'Full Deployment' and Location	If the first part of the project is more successful in its predictions, full deployment would include Sensor IQ aggregation/analysis on SmartMeters in Tier 2 & Tier 3 HFTDs and/or on select SmartMeters throughout the system, to be determined. If the second part of the project is more successful in its predictions, select or all SmartMeters would need to be upgraded to the next generation meters, or the BTM electrical condition detection sensor would need to be installed in select

TABLE:
EPIC 3.43: MOMENTARY OUTAGE INFORMATION
(CONTINUED)

	or all customer premises. Regardless of which part of the project is deployed, it would also include: Verified predictive analytics developed through application of data analytics platform toolsets and methods Multiple algorithms for determining equipment failure or underperformance risk in key categories (transformers, cabling, insulators, etc.) Integration of data streams and alerts into operational tools Ongoing tuning of algorithms and analytics using data analytics platform capabilities.

TABLE:
WIND LOADING ASSESSMENTS

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	Excessive wind loads on PG&E's distribution poles may cause asset failure that in turn increases wildfire ignition risk. This project aimed to reduce risk by providing asset intelligence to identify locations that required corrective actions driven by pole safety factors or limitations for wind speeds, for both individual poles and lines of up to 300 poles. The project leveraged existing LiDAR data from vegetation management efforts to geo-correct pole locations. Objectives of this project included a greater understanding of failure modes, establishment of a common repository of data gathered, and effectively updating workflows of key asset systems to align with new data strategies. Wind loading segmentation was performed to identify the wind loading of each asset on a support structure with the objective of integrating findings into risk models.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	A. Risk assessment and mapping 2. Ignition risk estimation D. Asset management and inspections 16. Asset inventory and condition assessments
(ii).A: Project Phase	Closeout
(ii).B: Project Status	This project has closed out and the resulting technology is now in a deployment phase, with the Wind Loading Assessment application being deployed to estimators as well as to external vendors doing desktop reviews of PG&E Distribution poles.
(ii).C: Project Location	PG&E service territory (PG&E owned distribution poles)
(iii).A: Results to Date	Q3 AND OCTOBER 2021 The project has closed out. Q2 2021 Completed the deployment to an additional 221 Distribution estimators, bringing the total to 373 (of 800) estimators using the new application. Deployed to the Desk Top Reviewer contract staff (66 staff), who review existing Distribution poles for safety. Further upgrades to improve synchronization of pole location corrections identified between the new software and PG&E's GIS application. Q1 2021 Additional upgrades to the modeling software to improve estimator productivity.

**TABLE:
WIND LOADING ASSESSMENTS
(CONTINUED)**

	Improved the process for determining conformance to FAA pole height/flight path obstruction clearance requirements. Completed the deployment to 152 (of 800) Distribution estimators using the new application. Q4 2020 Upgraded the foundational modeling software to handle “tree poles” and crossarm framing automation. Implemented a Citrix version of Wind Loading that allowed PG&E to switch to a less expensive third party Desk Top Review (pole loading review) vendor. Consolidated all Distribution wind loading data onto a PG&E platform. Completed the initial deployment stage of the project, with 62 (of 800) Distribution estimators using the new application.
(iii).B: Lessons Learned	Data integration into external cloud environment has the potential to provide significant benefit by enabling greater data access and data sharing capabilities with external partners. Data sharing through the external environment requires new methods for cybersecurity when sharing data externally. LiDAR holds potential in enabling PG&E to geo-correct pole configurations and arrangements in an automated fashion, which will be further explored through the next phase of this project.
(iii).C: Quantitative Performance Metrics	Accurate data for pole loading calculations. Target: Pass Actual Results: Pass Integration of data into an external cloud environment for greater accessibility. Target: Pass Actual Results: Pass Ability of a separate downstream project to perform pole geo-correction based on this project’s LiDAR data. Target: Pass Actual Results: Pass
(iii).D: Quantitative Risk Reduction Benefits	This project is foundational and therefore Quantitative Risk Reduction Benefits are not applicable. This project’s technology will supplement existing technology as an input to better assess and predict pole loading. Its output does not solely provide information to identify corrective actions, but enhances existing operations to identify pole overload conditions.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	Integrate data provided through wind loading assessment for failure mode insights to inform manual inspection cycles (integration would occur through a separate project). Pole geo-corrections will assist field crews in identifying correct pole locations in the field.

TABLE:
WIND LOADING ASSESSMENTS
(CONTINUED)

(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Data provided through this project can provide insights for proactive asset management practices (e.g., integrate results into distribution risk model).
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	Wind loading segmentation analysis will be performed to identify the wind loading of each asset, e.g., a conductor, on a support structure and integrate findings into appropriate systems. This will provide asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds, or to assess the safety factor of distribution poles as part of the preparation to exit a PSPS event. In addition, geo-corrections to pole locations can be determined based on LiDAR data.

Program Area: Foundational – New or Emerging Technologies

Foundational new or emerging technologies, including grid communication tools and control networks, can enable greater exchange of information required to provide real or near-real time operational visibility across the grid for enhanced decision-making including for PSPS events. These foundational items can also increase the flexibility of the grid, providing fundamental capabilities to advance system resiliency.

TABLE:
EPIC 3.03: ADVANCED DISTRIBUTION ENERGY RESOURCE MANAGEMENT SYSTEM

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Project Objective and Summary	The EPIC 3.03: Advanced Distributed Energy Resource Management System (DERMS) demonstration project seeks to design, procure, and deploy a prototype enterprise DERMS providing foundational operational capabilities which will support situational intelligence and broader wildfire mitigation efforts including remote grids, microgrids, and other Distribution Investment Deferral Framework opportunities (i.e., Non Wires Alternatives). This project includes the development of a cost-effective solution for providing advanced situational awareness and control capabilities for operators to manage DERs, dispatch DER registration data requests and monitor smart inverter-based DERs. As part of the effort to lower the cost of telemetry for interconnected DER assets, PG&E is engaging with vendors that would eventually produce PG&E-certified site gateways. Additionally, the project is engaging with potential DER aggregator partners to evaluate feasibility of integrating with the PG&E DER Headend Server as an alternative to the site gateway approach. Anticipated benefits of this project once deployed at scale include an increased situational awareness of DER grid impacts which could allow for greater operational flexibility to safely reconfigure the grid during PSPS, and a potential reduction in the number of customers impacted from PSPS events through microgrid technologies. We note that this project's technology is foundational; actual reduction is dependent on broader microgrid implementations.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	C. Grid Design and System Hardening: 12: Grid design for minimizing ignition risk 13. Grid design for resiliency and minimizing PSPS
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Third-party site gateway vendors have begun interoperability testing with the DER Headend Server. PG&E is working on implementing these gateways at five active pilot sites by the end of 2021. PG&E is engaged with a partner to include aggregator communications between their sites and our server. Business processes are being developed for a Q1 2022 handoff to the production owners.

TABLE:
EPIC 3.03: ADVANCED DISTRIBUTION ENERGY RESOURCE MANAGEMENT SYSTEM (CONTINUED)

(ii).C: Project Location	Humboldt County. Additional pilot sites have been identified in Fresno, Alameda, Contra Costa, and Solano counties.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 Additional demonstration sites have been selected with the Electric Generation Interconnection department. Effective October 4, 2021, the CPUC has mandated that PG&E offer customer-owned telemetry to interconnection customers that are required to provide telemetry for their projects (1MW or greater in size). In response, the project team has submitted an Advice Letter with PG&E's implementation plan and system specifications for providing the customer-owned telemetry option to interconnection customers that have applied following the effective date while in this interim pilot period before the system is in full production. PG&E internal business systems were updated so that projects with telemetry are automatically updated into the Graphical Information System (GIS), Distribution Management System (DMS), and Electric Distribution operational data platforms for use by Distribution Control Center (DCC) operators. The team has initiated interoperability with an aggregator partner to test aggregator functionality. Significant progress has been made on interoperability of vendor gateways with the PG&E IEEE 2030.5 server and with the telemetry solutions. The result is that there are now two PG&E certified third-party gateway vendors. The team is still fixing issues including ones that currently require restarting the server, as well as an issue with supporting multiple end device Long Form Device Identifiers (LFDI) from the same gateway. Testing with the control function will start at the beginning of 2022. Q2 2021 Selected a third gateway device manufacturer vendor to build an interoperable remote site gateway device. Q1 2021 Common Smart Inverter Profile (CSIP) certification of the Institute of Electrical and Electronics Engineers (IEEE) 2030.5 standard compliant DER Headend Server achieved. This certification increases the likelihood of interoperability between the PG&E-approved gateway devices and PG&E's DER Headend server. Installation of the pilot gateway device at the pilot site is complete. This installation allows the project team to test the system in the real-world environment. Q4 2020 Completed design and installation of IEEE 2030.5 DER Headend Server (CSIP certification pending)

TABLE:
EPIC 3.03: ADVANCED DISTRIBUTION ENERGY RESOURCE MANAGEMENT SYSTEM (CONTINUED)

	Gateway device installed at the pilot site to test telemetry and control (testing in progress). To build a market for remote site gateway devices for DER developers, PG&E selected two vendors for development of additional third-party remote site gateways meeting PG&E standards and requirements. This also set up a pathway for future vendors to develop their own remote site gateways.
(iii).B: Lessons Learned	Technology ecosystem for DER integration utilizing the IEEE 2030.5 protocol is still rapidly evolving and is not yet "plug and play." Further interoperability testing and industry collaboration is required. Technology architectures for integrating critical operational systems with 3rd party owned devices needs multiple levels of cybersecurity.
(iii).C: Quantitative Performance Metrics	Ability to meet CPUC telemetry maximum cost and minimum functionality requirements for each DER site or DER aggregator. Target: Pass Actual Results: Not available at this time.
(iii).D: Quantitative Risk Reduction Benefits	This project is foundational and therefore Quantitative Risk Reduction Benefits are not applicable. See the Remote Grids and EPIC 3.11 Multi-Use Microgrid projects as they partially depend upon this foundational project for their Quantitative Risk Reduction Benefits.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	This project will demonstrate capabilities to: Enhance situational awareness and DER control capabilities for distribution operators to support grid needs as part of wildfire mitigation related initiatives. Enable PG&E to dispatch registration data requests to verify compliance of Smart Inverters with Rule 21 curve settings and monitor Smart Inverter- based DERs to maintain safe and reliable grid operations during PSPS and normal grid conditions.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The DERMS would be integrated into the distribution system operators' systems and processes as described in (iv).A. The project team is also coordinating with the Advanced Distribution Management System (ADMS) team (see the ADMS report below) for future integration to optimize DER utilization and system-wide grid services.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product is a fully integrated enterprise DER Headend that can scale to accommodate the growth of managed DERs over time. The headend server will be located at PG&E and the remote site gateways will be located at customer DER sites.

TABLE:
ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Project Objective and Summary	PG&E is undertaking the first component of a multi-year effort to implement an ADMS which will, when fully deployed, integrate into a single platform several of the current mission-critical Distribution Control Center (DCC) applications (Distribution Supervisory, Control and Data Acquisition (D-SCADA) software, Demand Management System, and Outage Management System (OMS)) 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. ADMS impacts grid resiliency through: (i) facilitation of DER integration; (ii) switching operation enablement during PSPS events by providing more timely and accurate data to operators; (iii) identification of devices within fire areas to allow operators to disable reclosing relays when weather and conditions pose significant risk to the system.
(i).C: UWMMM Categories & Capabilities Potentially Impacted	F. Grid operations and protocols 27. Protective equipment and device settings 28. Incorporating ignition risk factors in grid control
(ii).A: Project Phase	Multiple (phase varies with functionality considered)
(ii).B: Project Status	The software has been released as expected and testing has begun.
(ii).C: Project Location	Applicable to the entire PG&E electric distribution service territory.
(iii).A: Results to Date	Q3 AND OCTOBER 2021 System Acceptance Testing including testing of the Wildfire Mitigation functionality began in October. Testing will continue through to Q2 2022 at which time the User Acceptance Testing is planned to complete. Q2 2021 Initial functional testing for wildfire mitigation functionality has begun. Testing will continue through to Q2 2022 at which time the User Acceptance Testing is planned to complete. Q1 2021 Software Build for wildfire mitigation functionality is 85 percent complete. Testing of beta version of completed functionality occurred in Q1 2021. Q3 2020/Q4 2020 Performing software build for wildfire mitigation functionality.

TABLE:
ADVANCED DISTRIBUTION MANAGEMENT SYSTEM
(CONTINUED)

(iii).B: Lessons Learned	None to date

TABLE:
ADVANCED DISTRIBUTION MANAGEMENT SYSTEM
(CONTINUED)

(iii).C: Quantitative Performance Metrics	Identification of automatic reclosing devices (e.g., Line Reclosers, Trip Savers, Fuse Savers) within fire areas and presentation of the potentially impacted areas to operators for verification (to inform reclosing relay disablement). Target: Pass Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	This project is foundational and therefore Quantitative Risk Reduction Benefits are not applicable. Quantitative Risk Reduction Benefits may be potentially derived through the multiple systems built upon this foundation.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	PG&E is taking a phased approach to ADMS implementation to ensure that foundational capabilities are first established. Operator training simulator is planned for SCADA system and reclosing relay capabilities will help train operators on ADMS functionality to ensure timely adoption of ADMS platform.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	ADMS is a platform used for distribution operations. Operators will require training on the system and former systems will need to be sunset in a methodical manner that minimizes disruption to ongoing operations. Change management practices focused on people, process, and technology will be employed to ensure value streams from ADMS implementation are captured.
(v).A: 'End Product' at 'Full Deployment' and Location	Multi-year ADMS deployment will integrate several mission-critical DCC applications that are currently spread across multiple platforms. This technology will enable the visibility, control, forecasting, and analysis required from a more dynamic grid. When fully deployed, the ADMS platform will bring the capabilities of today's D-SCADA software, DMS, and OMS into a single platform. Integrating these systems 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 and resiliency, while responding to future needs associated with the growth of DERs and complexities from wildfire risk.