ACTION PGE-18 (Class B) Attachment:

2021WMP_ClassB_Action-PGE-18_Atch01.docx

Per "Action PGE-18 (Class B)" in Section 5.1.7 of the "Wildfire Safety Division Evaluation of Pacific Gas and Electric Company's First Quarterly Report" dated January 8, 2021, below is Pacific Gas and Electric Company's (PG&E) Supplemental Filing of Section 7.1.D New or Emerging Technologies. Note that "Action PGE-18 (Class B)" specifies that PG&E add a column to Attachment 1. This is because PG&E filed the first quarterly report for Condition Guidance 9 in spreadsheet form. For ease of review, PG&E converted Attachment 1 to a document table format in Section 7.1.D.3 when filing the 2021 Wildfire Mitigation Plan (WMP). The content below from Sections 7.1.D 1-3 is unchanged as compared to the original 2021 WMP filing apart from the following:

- Caveats referring to this supplemental filing have been removed.
- In Section 7.1.D.3 the response item descriptions for (iii).C: Quantitative Performance Metrics and (iii).D: Quantitative Risk Reduction Benefits have been revised to include the general background and overview information about methodologies that were used to create the revised responses to these two response items.
- For each of the 18 projects in this portfolio, the (iii).C: Quantitative Performance Metrics and (iii).D: Quantitative Risk Reduction Benefits response items have been revised according to the methodologies referred to above.

While there is an inherent degree of uncertainty in the potential performance and benefits of New or Emerging Technology projects, PG&E appreciates the California Public Utilities Commission's desire to establish objective measures for assessing the progress of in-flight projects as well as the benefits that may be realized if technologies are subsequently deployed at scale. PG&E has taken foundational steps in this filing towards this objective and will continue to make enhancements in subsequent quarterly updates.

7.1.D.1 Impact on Strategies

PG&E actively explores new or emerging technologies that can mitigate wildfire risk and associated potential impact on public safety. Section 7.1.D details technology-driven innovations focused on wildfire mitigation consistent with the following definitions:

- New: *Technologies or analytical methods enabled through technology that were new to PG&E after the release of its 2019 WMP (i.e., February 6, 2019), exclusive of 'emerging' technologies*

- Emerging: *Pre-commercial technologies or analytical methods, including Technology Demonstration and Deployment (TD&D) projects*[1]

These technologies or analytical methods hold significant promise to advance PG&E's wildfire risk mitigation, bolster operational capabilities, increase the flexibility of the grid, and allow for greater system resiliency. Capabilities targeted through new or emerging technologies include, but are not limited to:

- Situational awareness and forecasting: New or emerging technologies can enable more accurate forecasting and identification of environmental events and operating conditions that pose a risk to the grid so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires.

- Grid design and hardening: New or emerging technologies can enable innovative system hardening techniques (e.g., new grid topologies or new resilience and Public Safety Power Shutoff (PSPS) avoidance technologies or techniques) to mitigate the risk of fire ignition and potential impacts on public safety.

- Asset management and inspections: New or emerging technologies can enable automated and improved methods to identify asset or system issues so that high risk items can be addressed prior to failure.

- Vegetation management and inspections: New or emerging technologies can enable more timely and accurate insights on vegetation health, density and proximity to assets allowing PG&E to implement risk-based vegetation management work practices to further ensure high risk areas are efficiently addressed.

- Asset Analytics and Grid Monitoring: New or emerging technologies can leverage data to enable greater insights on asset health to optimize system maintenance and implement proactive measures to reduce the risk of asset failure.

1 The TD&D demonstration project definition was approved by the CPUC in Decision (D.) 12-05-037, page 37: "The installation and operation of pre-commercial technologies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments, to enable the financial community to effectively appraise the operational and performance characteristics of a given technology and the financial risks it presents."

- Foundational Enablement: 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. These foundational items can also increase the flexibility of the grid, providing fundamental capabilities to advance system resiliency.

The projects included in this section are arranged according to these targeted capability areas above and are referred to as Program Areas in the project reports below.

The impacts of new or emerging technologies on utility strategy will vary by project. Information on the strategic enablement of these technologies is detailed further in Sections 7.1.D.2 and 7.1.D.3 below. The scope and implementation of these projects are subject to change due to the evolving nature of technology and business needs. There will likely be technologies that develop or mature over the reporting timeframe (2021-2023) which PG&E may pursue that are not described in Section 7.1.D.3. Projects that newly meet the inclusion criteria after the filing of the 2021 WMP update will be added to the WMP Conditional Approval Guidance Item 9 quarterly reports.

7.1.D.2. Implementation Approach and Integration of New or Emerging Technologies

The projects included in this Section 7.1.D are managed as a portfolio of wildfire mitigation-related new or emerging technology projects. Currently eight of the projects in this portfolio are also administered under PG&E's Electric Program Investment Charge (EPIC) program.

The EPIC program, established by the CPUC in 2011 through D.11-12-035, provides PG&E with an opportunity to demonstrate the value of emerging technologies that could advance a broad array of objectives including wildfire safety, grid safety, resiliency and reliability as well as customer enablement, and integration of renewable and distributed energy resources. CPUC has established rules that guide the EPIC program through its various rulings within the program docket. PG&E governs our EPIC program administration to ensure compliance with the CPUC rules and effective use of the program funding. In selecting emerging technologies for demonstration, we assess criteria that may inform project value and successful implementation, including: (i) alignment to key program objectives, (ii) technology novelty, (iii) technology readiness, (iv) sponsorship and clear path to production, (v) obstacles to implementation, and (vi) potential benefits at demonstration and full deployment stages. PG&E also assesses alignment to utility strategic priorities and customer needs to ensure that technologies, if successfully demonstrated, will enable PG&E (and potentially other utilities) to better serve our customers and deliver on program objectives, including enhancements to safety and grid resiliency.

EPIC demonstration projects aid in identifying key requirements and insights to inform broader deployment in a manner that strategically aligns the integration of technologies with existing operations. Given the rapidly evolving energy landscape and the impact of climate change in California, the continuation of technology innovation programs like EPIC is critical to the continued advancements of grid capabilities to enable advancements on safety and resiliency.

Consistent with CPUC guidance, PG&E has relied primarily upon the EPIC program to demonstrate emerging technologies to improve our ability to mitigate wildfire risk, although the wildfire mitigation new or emerging technology portfolio, as reported on in this section, also includes new technology projects that are not pre-commercial in nature. These projects are funded and managed separately from the EPIC portfolio according to standard (non-EPIC) business planning processes.

The EPIC 3 program cycle now underway is the final triennial cycle in the current EPIC program. The Commission is currently contemplating in the EPIC successor program proceeding, R.19-10-005, whether the IOUs will continue to administer their respective portions of the EPIC program to develop capabilities that reduce wildfire risk and address other critical California objectives.

PG&E will continue to seek funding and authorization to pursue demonstration projects for new and emerging technology related to wildfire mitigation through the EPIC successor program (if authorized), through our 2023 GRC request (if the Commission does not authorize continued IOU administration of the EPIC program), or through other funding mechanisms.

7.1.D.3. New or Emerging Technologies – Project Details

This section provides an overview of 18 mitigations that leverage new or emerging technologies, including 16 projects that were previously included in Section 5.1.D New or Emerging Technologies in the 2020 WMP. On June 11, 2020 the CPUC approved the Wildfire Safety Division's (WSD) recommendation for a Conditional Approval of PG&E's 2020 WMP. In the Conditional Approval recommendation, the WSD identified in Guidance Item 9 that PG&E had an "Insufficient discussion of pilot programs" and recommended quarterly reporting on these projects. As this was identified as a deficiency of the 2020 WMP, these projects are reported herein according to the Guidance Item 9 reporting criteria, in addition to being reported in the ongoing quarterly reports.

In addition to the New or Emerging criteria (listed in Section 7.1.D.1) for inclusion in this section, the project must also at least be in the Planning phase (as described below) with an approved business case and a planned budget. Projects that newly meet the inclusion criteria after the filing of the 2021 WMP will be added to the 2020 WMP Conditional Approval Guidance Item 9 quarterly reports.

The portfolio of projects addressed in this section begins with the projects included in the 2020 WMP, and accounts for the removal of projects that have been closed and the addition of newly launched projects.

The following projects included in the New or Emerging Technology section of the 2020 WMP have been removed from the New or Emerging Technology section of the 2021 WMP. The first four projects below are either now in production or in the process of entering production and continue to be included in other sections of the 2021 WMP. The last project has completed and is not planned to be taken to production. They are:

- *5.1.D.3.1 Wildfire Spread Models. The wildfire spread model is now in production with over 70 million virtual fires simulated by the technology each day every 200m along PG&E's overhead assets in the High Fire Threat Districts (HFTD).*

- *5.1.D.3.2 Satellite Fire Detection. The data and workflows of this project are now in production and are providing detection of potential wildfire conditions to inform operational response. In addition, PG&E also sends automated email fire alerts to various partners and has developed a public facing web page where these detections are available.*

- *5.1.D.3.3 Weather Model and Fire Potential Index – Model Expansions. The 2 kilometer model pipeline of weather, fuels, Outage Producing Wind model, and Fire Potential Index are now in production in the external cloud environment. These models and tools inform daily fire danger risk, Public Safety Power Shutoff decision-making frameworks, and outage potentials which can be modeled through PG&E's Storm Outage Prediction Project Model.*

- *5.1.D.3.19 EPIC 2.34: Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors (Distribution Fault Anticipation (DFA)*

Technology). The technology demonstration project was completed. For more information on how this project is continuing into production and wider deployment, see Section 7.3.2.2.3 DFA Technology and Early Fault Detection.

- *5.1.D.3.11 Ultrasonic Technology (UT). This project was removed because UT defect detection was found to be unreliable at this time. Additional project details from the last project quarterly report prior to removal can be found in the 2020 WMP Conditional Approval Guidance Item 9 Second Quarterly report available from the CPUC website.*

For the 2021 WMP, PG&E has newly included the EPIC 3.41: Drone Enablement and Operational Use and EPIC 3.43: Momentary Outage Information projects in this section.

Below are four EPIC projects that PG&E may pursue to demonstrate additional wildfire risk reduction capabilities, subject to CPUC approval of Advice Letter 6043-E to conduct these proposed projects as part of the current EPIC 3 investment cycle:

- *Project 44 – Advanced Transformer Protection: Demonstrate and evaluate the use of negative sequence transformer differential protection to provide high sensitivity fault detection and prevent transformer winding failures.*

- *Project 45 – Automated Fire Detection from Wildfire Alert Cameras: Demonstrate an automated fire detection model using machine learning, computer vison, or artificial intelligence (AI) techniques that accurately detects fires based on visual and infrared (IR) camera data streams; optimize for automated fire detection alerts.*

- *Project 46 – Advanced Electric Inspection Tools – Wood Poles: Demonstrate and evaluate the use of a nondestructive examination method (Radiography Testing) to detect flaws and prevent potential failures on electric distribution wood poles.*

- *Project 47 – Operational Vegetation Management Efficiency Through Novel Onsite Equipment: Demonstrate new technologies and onsite processes that can materially lower vegetation management costs by: (a) small scale mobile torrefaction, and (b) wood baling technologies.*

If and when any of these projects is approved, the project will be added to the subsequent 2020 WMP Conditional Approval Guidance Item 9 quarterly report as well as the next annual WMP update.

The New or Emerging Technology projects included in this 2021 WMP are summarized in the table below. Comprehensive details of each of the projects follow this table.

TABLE PG&E-7.1.D.3: NEW OR EMERGING TECHNOLOGIES

Section	Project Name	Program Area	Approximate 2021 Project Financial Forecast ($K)[2]
7.1.D.3.1	SmartMeter™ Partial Voltage Detection	Situational Awareness & Forecasting	$331
7.1.D.3.2	Line Sensor Devices	Situational Awareness & Forecasting	$6,420
7.1.D.3.3	EPIC 3.15: Proactive Wires Down Mitigation Demonstration Project (Rapid Earth Fault Current Limiter)	Grid Design & System Hardening	$3,030
7.1.D.3.4	Distribution, Transmission, and Substation: Fire Action Schemes and Technology (DTS-FAST)	Grid Design & System Hardening	$30,000
7.1.D.3.5	Remote Grid	Grid Design & System Hardening	$1,382
7.1.D.3.6	EPIC 3.11: Multi-Use Microgrid	Grid Design & System Hardening	$1,440
7.1.D.3.7	Enhanced Asset Inspections—Drone/AI (Sherlock Suite)	Asset Management and Inspections	$7,753
7.1.D.3.8	Below Ground Inspection of Steel Structures (Steel Transmission Structure Corrosion Assessment and Mitigation Pilot)	Asset Management and Inspections	TBD
7.1.D.3.9	EPIC 3.41: Drone Enablement	Asset Management and Inspections	$1,583
7.1.D.3.10	Mobile Light Detection and Ranging (LiDAR) for Vegetation Management	Vegetation Management and Inspections	TBD
7.1.D.3.11	EPIC 3.13: Transformer Monitoring via Field Area Network (FAN)	Asset Analytics & Grid Monitoring	$1,267
7.1.D.3.12	EPIC 3.20: Maintenance Analytics	Asset Analytics & Grid Monitoring	$541
7.1.D.3.13	EPIC 3.32: System Harmonics for Power Quality Investigation	Asset Analytics & Grid Monitoring	$761
7.1.D.3.14	Sensor IQ	Asset Analytics & Grid Monitoring	$533
7.1.D.3.15	EPIC 3.43: Momentary Outage Information	Asset Analytics & Grid Monitoring	$1,358

2 Financial forecasts for emerging technology assessment or deployment projects are highly tentative as uncertainty regarding costs and functionality is very high for new technologies. The forecast shown reflects project costs only (not production costs if the results of the project lead to production), are estimates as of January 2021, and are subject to change, including but not limited to the fact that several of the project estimates remain TBD at this time. Costs beyond 2021 have not yet been defined given this level of uncertainty.

Section	Project Name	Program Area	Approximate 2021 Project Financial Forecast ($K)[2]
7.1.D.3.16	Wind Loading Assessments	Asset Analytics & Grid Monitoring	$1,715
7.1.D.3.17	EPIC 3.03: Advanced Distribution Energy Resource Management System	Foundational	$1,496
7.1.D.3.18	Advanced Distribution Management System (ADMS)	Foundational	$1,000[3]

In accordance with addressing the deficiency noted above by the WSD in PG&E's 2020 WMP, the standardized project information is provided in the following format arranged according to the five Condition Items noted in that deficiency, with expansion by PG&E into multiple targeted, detailed responses:

Condition Item (i): All pilot programs or demonstrations identified in WMP.	
The projects are summarized in the table above and the following is the template for the detailed reporting that is provided for each project, below.	
Information Type	*Description*
(i).A: Project Type	Either New Technology (Commercially Available Offering) or Emerging (Pre-commercial) Technology according to the definition provided in Section 7.1.D.1 above.
(i).B: Additional References in the 2021 WMP	Other sections where this project is also significantly detailed within the WMP.
(i).C: Section in the 2020 WMP	If applicable, the section number of this project in the New or Emerging Technologies section of the 2020 WMP.
(i).D: Project Objective and Summary	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.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	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.
Condition Item (ii): Status of the pilot, including where pilots have been initiated and whether the pilot is progressing toward broader adoption.	
Information Type	*Description*
(ii).A: Project Phase	The project phase is reported according to the following definitions:

Project Phase	Definition
Initiation	• Project purpose and benefits defined • Initial scope, schedule, budget • Sponsor, stakeholders, project team defined

[3] This figure represents the portion of this project related to wildfire mitigation.

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<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>
<tr><td>Staging</td><td>• Review and confirmation of project alignment with purpose, benefits, scope, budget, schedule
• Key success factors defined</td></tr>
<tr><td>Build/Test</td><td>• Build, test and demonstration
• Evaluation to defined metrics</td></tr>
<tr><td>Closeout</td><td>• Path to production revised
• Lessons learned documented
• Decommissioning completed
• Final report</td></tr>
<tr><td>Continuous Improvement</td><td>• Optional phase that some projects progress to when there is project-related continuous improvement activity post Closeout.</td></tr>
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<tr><td>(ii).B: Project Status</td><td>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.</td></tr>
<tr><td>(ii).C: Project Location</td><td>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 HFTDs or systemwide.</td></tr>
<tr><td colspan="2">Condition Item (iii): Results of the pilot, including quantitative performance metrics and quantitative risk reduction benefits.</td></tr>
<tr><td>Information Type</td><td>Description</td></tr>
<tr><td>(iii).A: Results to Date</td><td>Results of pilot projects are provided through Q4 2020. 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.</td></tr>
<tr><td>(iii).B: Lessons Learned</td><td>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.</td></tr>
<tr><td>(iii).C: Quantitative Performance Metrics</td><td>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, 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</td></tr>
</table>

	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.
(iii).D: Quantitative Risk Reduction Benefits	Quantitative risk reduction benefits that may result from adoption and deployment of the technology are provided for projects in this portfolio, as appropriate. The risk model used to calculate the potential quantitative risk reduction benefits is PG&E's Enterprise Risk Model for which the wildfire risk assessment and bowtie analysis is described in Section 4.2 Subsection (b) of the 2021 WMP. The estimated potential risk scores provided for individual projects range from 22 to 1,125 and are in relation to the baseline risk score of approximately 25,000. For further explanation, please see Subsection (b) as referred to above. Note that the estimated potential risk reduction is calculated for each technology independent of the effects of other technologies working on the same geography or asset. This is further explained in the document "RSE Lite Methodology WMP 2021.pdf" filed with the 2021 WMP. The estimated risk reduction considers the total potential risk reduction impact at full technology deployment (e.g. system-wide, Tier 2 & 3 HFTDs, or specific types of distribution circuits) depending on the specific assets or geographic scope where the technology is applicable, and independently of any other risk reduction projects. In order to normalize the variations in scope for technology deployment, estimated potential risk reduction is normalized per mile in the results. Along with the calculated benefits provided using this methodology, the underlying assumptions and short explanations are provided as needed. There is inherent uncertainty in the assumptions and estimates that are developed to create the quantitative risk reduction benefits. Risk reduction benefits should be viewed as initial potential estimates if the technology is proven successful and will be refined in subsequent updates, as assumptions around the types of assets impacted, the applicable scope of deployment, and the effectiveness of the technologies are refined. Projects classified as foundational do not lend themselves to the calculation of a quantitative risk reduction benefit. 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.
Condition Item (iv): How the electrical corporation remedies ignitions or faults revealed during the pilot on a schedule that promptly mitigates the risk of such ignition or fault and incorporates such mitigation into its operational practices.	
Information Type	*Description*
(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.

Condition Item (v): A proposal for how to expand use of the technology if it reduces ignition risk materially.	
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 through this section, including but not limited to project next steps, expected results, and potential quantitative risk reduction benefits, are subject to change due to the evolving nature of technology and drivers of system and public safety risk.

The projects described below are organized by Program Areas.

Program Area: 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.

7.1.D.3.1 SmartMeter Partial Voltage Detection

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	This project is described in Section 7.3.2.2.2: Situational awareness and forecasting - SmartMeter Partial Voltage Detection (Formerly Known as Enhanced Wires Down Detection)
(i).C: 2020 WMP Section	5.1.D.3.4
(i).D: Project Objective and Summary	PG&E's EPIC 1.14: Next Generation SmartMeter Telecom Network Functionalities project demonstrated that the SmartMeter Telecommunications Network (SMN) 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 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 Distribution Management System 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. Phase 1 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 Distribution Management System (DMS) during the event. Phase 1 of this project completed in 2019 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 is underway. It applies to ~365K 3-phase SmartMeter electric meters and relies upon the implementation of firmware detection of partial voltage conditions. The Phase 2 technology is intended to alert on partial voltage conditions on 4-Wire systems where transformers are connected line-to-neutral.

(i).E: Utility Wildfire Mitigation Maturity Model (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: Design/Engineering (~365K three-phase meters in scope).
(ii).B: Project Status	Phase 1 is in production and has been deployed to ~4.5M meters. Phase 2 is in a development phase with the intent of deployment to 365K meters in Tier 2 and Tier 3 HFTDs by the end of Q2 2021, though this deployment intent is at risk due to a vendor product issue that is currently being assessed.
(ii).C: Project Location	Phase 1: Tier 2 & 3 HFTDs were initially targeted; now deployed system-wide. Phase 2: Targeting system-wide deployments.
(iii).A: Results to Date	Q3 2020/Q4 2020 Phase 2 Project Results: • Meter firmware vendor contract finalized. • Design of Distribution Management System (DMS) data presentation for operator use. • SmartMeter firmware functionality testing complete • SmartMeter firmware deployment planning complete
(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 Distribution Management System (DMS).
(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 is not possible to get to zero due to operational conditions and technical limitations. • 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).
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 265 Risk Drivers: Consequence of Fire Deployment Scope Assumption: System-wide The risk mitigation potential is driven by a 7% estimated effectiveness in the ability to reduce the consequence of wildfire ignition risk through faster response time due to partial voltage and/or wire down conditions.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	Phase 1 • Currently in production. Phase 2 • None at this time.

(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 is that the partial voltage detection firmware will be deployed to all compatible PG&E SmartMeter electric meters system-wide, with system optimization completed, and functionality integrated into the Distribution Management System and Outage Management Tool, as described in (iv).B above.

7.1.D.3.2 Line Sensor Devices

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Additional References in the 2021 WMP	Section 7.3.2.2.5: Situational Awareness & Forecasting – Line Sensor Devices
(i).C: 2020 WMP Section	5.1.D.3.5
(i).D: 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).E: Utility Wildfire Mitigation Maturity Model (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 60 feeders covering a total of 4,898 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.
(ii).C: Project Location	Tier 2 & 3 HFTD in the North Bay, Sonoma, North Valley, Humboldt, Yosemite, and Sierra divisions.
(iii).A: Results to Date	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/maintenance. • Continued device deployment to circuits in HFTDs in the Humboldt, Stockton, Yosemite, and Sierra divisions. • Improved analytics methods and automation.
(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.
(iii).C: Quantitative Performance Metrics	• Percentage (%) of the events detected by sensors (e.g., grid disturbances from vegetation contact or line slap) resulting in identification of wildfire risk conditions requiring preventative action. • Target: ≥50%
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E’s Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E’s Enterprise Risk Model: Estimated Potential Risk Reduction Score: 410 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 risk and consequence of fire risk, specifically mitigating the equipment failure, vegetation drivers and financial, safety, and reliability consequences. The risk mitigation potential is driven by a 1.8% project effectiveness estimated through pilot data.
(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 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, Maintenance, and Field Operations functions to support faster fault identification (including location data) for proactive maintenance prior to high fire risk periods.

Program Area: 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 PSPS avoidance technologies or techniques). Mitigations leveraging new or emerging technologies include the following:

7.1.D.3.3 EPIC 3.15: Proactive Wires Down Mitigation Demonstration Project (Rapid Earth Fault Current Limiter)

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	7.3.3.17.4
(i).C: 2020 WMP Section	5.1.D.3.6
(i).D: 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 unit-grounded circuits, which make up the majority of PG&E's distribution circuits within HFTDs.
(i).E: Utility Wildfire Mitigation Maturity Model (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	All of the REFCL system equipment has been installed and initially tested. Further commissioning of the system is ongoing (as of late January) and a comprehensive testing program will begin in March 2021, with the project completed by July 2021. 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 REFCL installations has begun but is pending results and learnings of the Calistoga pilot project before design or field work starts on additional sites.
(ii).C: Project Location	Substation in a Tier 3 HFTD in the North Bay.
(iii).A: Results to Date	Q4 2020 • Completed substation construction and all the distribution field installations in Q4 2020.

(iii).B: Lessons Learned	• The Ground Fault Neutralizer (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% – False positive rate Target: ≤ 10% – False negative rate Target: ≤ 5% – GFN system availability/uptime (excluding external operations constraints) Target: ≥ 95% – Correct identification of faulted circuit and feeder breaker tripping Target: ≥ 95%
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E’s Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E’s Enterprise Risk Model: Estimated Potential Risk Reduction Score: 962 Risk Drivers: Equipment Failure Deployment Scope Assumption: ~3,500 miles of 3-wire/12kV distribution lines in Tier 2 & 3 HFTDs. The risk mitigation potential is driven by an estimated overall effectiveness of 58% using 2013-2018 distribution ignition data.

(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 (SEFM) relay interface controller is currently in development and is needed to integrate the GFN into operational practices and the Supervisory Control and Data Acquisition (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.

7.1.D.3.4 Distribution, Transmission, and Substation: Fire Action Schemes and Technology

1) Note: Due to the sensitive nature of the experimental, proprietary technology, PG&E is unable to disclose extensive details about the DTS-FAST pilot 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: Additional References in the 2021 WMP	8.1
(i).C: 2020 WMP Section	5.1.D.3.7
(i).D: Project Objective and Summary	DTS-FAST is an internal PG&E development and is currently in pilot phase. This technology pilot aims to use fraction-of-a-second technologies to detect objects approaching energized power lines and respond quickly to shut off power before object impact. PG&E is implementing a pilot to engineer, construct, install and monitor a new technology on a PG&E transmission circuit 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 pilot findings.
(i).E: Utility Wildfire Mitigation Maturity Model (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	Build/Test
(ii).B: Project Status	Pilot construction on a 115kV transmission circuit is 70% completed.
(ii).C: Project Location	Proof of concept completed at San Ramon, CA. Pilot being constructed on a 115kV transmission circuit.
(iii).A: Results to Date	Q3 2020/Q4 2020 • Engineering and construction details completed for pilot on 115kV transmission circuit.
(iii).B: Lessons Learned	Proof of concept model was tested and retested to confirm the technology, as designed, would meet the detection, speed and signal confirmation requirements for subsequent testing through a pilot.
(iii).C: Quantitative Performance Metrics	• The detection of objects approaching energized power lines and corresponding power shut off. Target: Power shut off prior to object impact.

(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 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	• Assess optimal locations for technology implementation. • Engage technology vendors for hardware needs. • Secure resourcing required for targeted implementation, including mitigation strategy for potential COVID-19 impacts.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	• Leverage pilot 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 of pilot. If successful, PG&E will consider a targeted approach to post-pilot implementation to help ensure high impact areas are first addressed, taking into account risk-based and feasibility assessments.

7.1.D.3.5 Remote Grid

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Additional References in the 2021 WMP	7.3.3.17.5
(i).C: 2020 WMP Section	5.1.D.3.8
(i).D: 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 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).E: Utility Wildfire Mitigation Maturity Model (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	Build/Test
(ii).B: Project Status	The projects are advancing through scoping, assessment, contracting, design, and permitting activities, building understanding of the many aspects required for a successful Remote Grid. The three leading projects (some comprising five remote grid sites) are in the permitting and construction stages. Initial projects have been delayed due to unforeseen permitting delays due to presence of threatened species. Additional sites under consideration are undergoing detailed feasibility assessment to address constructability and customer acceptance before down selecting to a complete set of initial projects.
(ii).C: Project Location	Three initial remote grid projects (some comprising multiple remote grid sites) are in Mariposa and San Luis Obispo counties. Additional projects in HFTDs in El Dorado, Madera, Fresno, Tulare, Santa Barbara, Yuba, and Sierra counties are currently being assessed.

(iii).A: Results to Date	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. Q3 2020 • Developed and awarded major update of contract, including updated technical specification. • Documented detailed protocol to identify and evaluate potential projects. Q4 2020 • Negotiated & executed a turnkey Purchase and Sale Agreement and a 10-year full-wrap Maintenance Agreement, forming a reusable template for future Standalone Power System 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[4] 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 Standalone Power System for a similar application.
(iii).B: Lessons Learned	• 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.
(iii).C: Quantitative Performance Metrics	• Safe operating hours (e.g. five Standalone Power System units for one year) without a safety or fire incident. Target: ≥ 50,000 hours • Portfolio uptime, average Target: ≥ 99% • Percent (%) Renewable Fraction of portfolio on average, with each Standalone Power System meeting applicable CARB emissions limits. Target: ≥ 60%
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model:

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

	Estimated Potential Risk Reduction Score: 347 Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: 452 miles of distribution lines in Tier 2 & 3 HFTDs 23.8 miles of distribution lines in Non-HFTD areas The risk mitigation potential is driven by an estimated overall effectiveness of 95%. This mitigation eliminates overhead feeder lines and therefore should address virtually all risk drivers. However, since remote grids serving multiple customers will likely add or maintain a small amount of overhead conductor to the system, PG&E makes a conservative estimate of 95% effectiveness.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The initial projects under way in 2020 are positioned as fully featured, long-term asset deployments with performance and reliability targets that will result in these projects eliminating segments of overhead line exposure. When these projects go online, an immediate ignition risk reduction can be realized upon de-energization of the infrastructure they replace.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Standardization of to-be-proven 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 needed to 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, it is more likely that a Remote Grid would be appropriate at the end of an overhead distribution feeder with small numbers of customers.
(v).A: 'End Product' at 'Full Deployment' and Location	If this project is determined to be successful, the Remote Grid concept would be developed as a standard service offering and considered alongside other risk mitigations, such as overhead hardening and undergrounding, and deployed wherever it is cost effective and feasible. Possible appropriate deployment locations would be at the ends of overhead distribution feeders that serve small numbers of customers in HFTDs.

7.1.D.3.6 EPIC 3.11: Multi-Use Microgrid

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	
(i).C: 2020 WMP Section	5.1.D.3.9
(i).D: 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 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).E: Utility Wildfire Mitigation Maturity Model (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. This specification along with the completed Concept of Operations (CONOPs) 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 United States Coast Guard station.
(iii).A: Results to Date	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. Q3 2020 • Started SCADA design (in progress) • Refined Functional Design Specification. • Completed communication and hardware fail-safes decisions Q4 2020 • Configuration of information points list and human-machine interface • Controller Test Plan aligned with third-party manufacturer • Utilized lessons learned from this project to publish a Community Microgrid Technical Best Practices Guide

(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. • Verify prior to system design that preferred communication systems, such as the 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	Pass/fail criterion: • Ability of the microgrid to safely and seamlessly energize the island and provide electric service throughout the duration of broader multi-hour grid outages.
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 1125 Risk Drivers: Consequence of Failure – PSPS Deployment Scope Assumption: Tier 2 & 3 HFTDs This initiative reduces the consequence of PSPS, specifically mitigating the impact to customers from PSPS events, with an effectiveness of 1.2%. This effectiveness is based on a case study of PG&E's PSPS impact reduction activities. We expect to see a risk reduction of 1.2% due to Mid-Feeder and Substation Microgrids relative to PSPS impacts from 2019.
(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	Full deployment for this project is a permanent and in-field microgrid at Arcata-Eureka Airport, with visibility and control from PG&E control center. The formalization and documentation of a repeatable process will enable a streamlined approach to deploying additional Multi-Use Microgrids as appropriate in HFTDs.

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 LiDAR data and drone imagery capture,[5] 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:

7.1.D.3.7 Enhanced Asset Inspections – Drone/AI (Sherlock Suite)

(i).A: Project Type	New Technology (Not Widely Commercialized)
(i).B: Additional References in the 2021 WMP	
(i).C: 2020 WMP Section	5.1.D.3.10
(i).D: 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 enhanced inspection program (WSIP), 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. 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,

5 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.

	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).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset inventory and condition assessments 18. Asset inspection effectiveness 20. QA/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 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	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. 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. 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
(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 queue (as compared with our January 2019 performance) Target: ≥ 50% • Percentage (%) reduction in imagery inspection time (as compared with our January 2019 performance) Target: ≥ 25% • 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.
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 31 Risk Drivers: Equipment Failure Deployment Scope Assumption: PG&E Transmission System-wide This analytics project assumes the ability to assess C-hook condition through AI algorithms and user input. The risk mitigation potential is driven by an estimated overall effectiveness of 10%, which is correlated 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.
(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, GIS), may be considered.

7.1.D.3.8 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: Additional References in the 2021 WMP	7.3.4.10
(i).C: 2020 WMP Section	5.1.D.3.12
(i).D: Project Objective and Summary	PG&E is implementing a pilot that will regularly inspect steel assets below groundline to detect steel corrosion and concrete degradation that may compromise structural integrity, with the goal of reducing risk of steel assets in the transmission steel structures. To inspect below ground, the foundations/footings of steel towers and poles are 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 would then be prioritized, based on the field evaluations and soil samples, in combination with other evaluations of tower/structure and overhead assets.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset inventory and condition assessments
(ii).A: Project Phase	Planning
(ii).B: Project Status	We continue to evaluate potential contractors prior to finalizing contracts.
(ii).C: Project Location	Approximately 1000 locations throughout the PG&E service territory, including in HFTDs, are planned.
(iii).A: Results to Date	Prior Results • Data analysis and project definition. • Structure selection and reaching out to contractors. • Designing the Field Experimentation through a selection of measurements that will provide PG&E the answers sought. Q3 2020/Q4 2020 • Project scope finalized • Structures for testing identified • Field operations processes and methods for project implementation documented.
(iii).B: Lessons Learned	None to date.
(iii).C: Quantitative Performance Metrics	Pass/fail criteria: • 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. • Ability to utilize the results of the pilot to validate the industry corrosion map. This map would then direct cathodic protection resources as well as corrosion abatement paint efforts towards the most at-risk structures in the system. • Ability to validate whether a correlation exists between atmospheric corrosion (as seen on steel members above ground) 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	If the project proves successful, it will provide high quality data inputs that can be used to inform asset maintenance decision-making. PG&E will assess findings and identify next steps based on findings of the project, including an assessment of the accuracy of estimating below ground corrosion based on above ground conditions.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	• Data can be integrated into asset management data models to help prioritize asset maintenance practices based on risk assessments. • Depending on findings of below ground corrosion conditions, PG&E may consider deploying cathodic protection to better protect from corrosion impacts. The pilot would help dictate where cathodic protection would be most impactful.
(v).A: 'End Product' at 'Full Deployment' and Location	• Broader implementation of below ground inspection of steel structures. • Data integrated into asset management data models to help prioritize asset maintenance practices based on risk assessments. • Depending on findings of below ground corrosion conditions, PG&E may consider deploying cathodic protection to better protect from corrosion impact.

7.1.D.3.9 EPIC 3.41 – Drone Enablement

(i).A: Project Type	New Technology (Not Widely Commercialized)
(i).B: Additional References in the 2021 WMP	
(i).C: 2020 WMP Section	This project was mentioned at the end of Section 5.1.D.3 New or Emerging Technologies – Project Summaries as a project that PG&E may pursue within EPIC.
(i).D: Project Objective and Summary	This project proposes to test the following two hypotheses: 1. 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. 2. 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).E: Utility Wildfire Mitigation Maturity Model (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 FAA regulatory requirements and process to provide critical support during the Design/Engineering phase of the project. The team has developed a preliminary project plan and has begun to document the details of each planned use case. These use cases will be translated into a Concept of Operations (CONOPS) document and then translated into technical requirements for the upcoming Request for Proposals (RFP) to identify a drone vendor partner. The team has also begun preliminary coordination with the FAA.
(ii).C: Project Location	Project location is TBD. The team is actively working with the consultant on site selection parameters that will both support the project's objectives and meet FAA requirements for BVLOS operations.
(iii).A: Results to Date	Q3 2020 • Business Plan approved 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
(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% • Percentage (%) of automated operations without errors or gaps in data capture that would require repeat operations Target: 99% 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%
(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 7.1.D.3.7 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 are tied to and accounted for in specific Asset Health and Performance Center projects and their associated sensors or analytics such as 7.1.D.3.2 Line Sensors and, in the 2020 WMP: 5.1.D.3.19 EPIC 2.34: Predictive Risk Identification with RF Added to Line Sensors (DFA Technology).
(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	1. 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 UAV for detailed inspections on all assets within scope. 2. 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 Distribution Control Center 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).

Program Area: Vegetation Management and Inspections – New or Emerging Technologies

PG&E is using a variety of technologies to improve our vegetation management 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. Vegetation Management 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:

7.1.D.3.10 Mobile LiDAR for Vegetation Management

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Additional References in the 2021 WMP	7.3.5.7
(i).C: 2020 WMP Section	5.1.D.3.13 (In the 2020 WMP, titled as "Mobile LiDAR for Distribution Inspections")
(i).D: Project Objective and Summary	This project seeks to validate that high-resolution data captured with vehicle and backpack-mounted LiDAR and imagery units can help reduce fire risk and improve compliance of PG&E's Vegetation Management (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.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	E. Vegetation management and inspections: 22. Vegetation inspection cycle 23. Vegetation inspection effectiveness 24. Vegetation grow-in mitigation 26. QA/QC for vegetation management
(ii).A: Project Phase	2019 Pilot: Closeout 2020 Pilot: Closeout 2021 Pilot: Planning
(ii).B: Project Status	Q4 2020: Closeout of 2020 Pilot Preparations are underway for an enhanced Mobile LIDAR collection effort in 2021.
(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: TBD
(iii).A: Results to Date	Prior Results • See (iii).B Lessons Learned below. 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.

(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 vegetation management (VM) processes. • Derived cost and data analysis cycle time performance measures for both vehicle and backpack-mounted sensors. In addition, PG&E has learned: • 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.
(iii).C: Quantitative Performance Metrics	• Scan analysis cycle time Target: TBD
(iii).D: Quantitative Risk Reduction Benefits	No Quantitative Risk Reduction Benefits have been identified at this time.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	When the Mobile LiDAR inspections process identifies a radial clearance issue in a region selected for scanning, the local Vegetation Management field operations team is informed and provided the data. Local operations will then consider the finding in context of their operations and then mitigate the identified clearance issue within the requisite timeframe.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	We will evaluate 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	The potential end product is the integration of Mobile LiDAR data outputs into select phases of the vegetation management radial clearing process in HFTD for road-side distribution corridors. Potential VM processes impacted include work verification and documentation.

<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:

7.1.D.3.11 EPIC 3.13: Transformer Monitoring via Field Area Network

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	
(i).C: 2020 WMP Section	5.1.D.3.14
(i).D: 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).E: Utility Wildfire Mitigation Maturity Model (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	Planning
(ii).B: Project Status	The team is evaluating TAD costs provided by vendors, obtaining site licenses to access vendors' servers to obtain TAD data, and preparing to compare data from the two TAD vendors.
(ii).C: Project Location	Initial planned locations are in the San Jose area.
(iii).A: Results to Date	Q3 2020 • Business plan approved for project implementation. • RFP executed for external TAD vendor involvement. • Construction contract executed. Q4 2020 • Business plan approved for project implementation. • External TAD vendors selected for demonstration project

(iii).B: Lessons Learned	None to date.
(iii).C: Quantitative Performance Metrics	Pass/fail criterion: 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.
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 50 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 an estimated overall effectiveness of 10%, which is correlated 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.
(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 subject to available funding.

7.1.D.3.12 EPIC 3.20: Maintenance Analytics

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	
(i).C: 2020 WMP Section	5.1.D.3.15
(i).D: 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's current focus is on distribution transformers.
(i).E: Utility Wildfire Mitigation Maturity Model (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	In Q4 2020 the team completed the first phase of the project which was focused on exploring voltage failures and anomalies while working with the Power Quality group. In coordination with the Asset Health and Performance Center, the second phase of the project is focused on ignition risks and catastrophic failures associated with failing equipment such as overloaded or near-failure transformers, stressed or near-failure cables, or primary side loose neutrals as well as from vegetation contact or other intermittent faults with overhead equipment.
(ii).C: Project Location	Algorithm testing and verification is ongoing throughout the PG&E service territory.
(iii).A: Results to Date	• Q2 2020 • Added heuristic to identify fuse failures. • The best prediction model had 87% precision when making predictions on a set of 300 failures. Q3 2020 • Field validation of predicted failing transformers (in progress) • Through iterative development, the best model has improved and now has 98% precision for predicted failures. Q4 2020 • Failure model minimum viable product (MVP) is in progress • Submitted change request to expand scope. The expansion of scope will hone project focus on identifying transformer failures with high ignition risk and identifying grid event behavior which may indicate vegetation contact or other faults on overhead equipment. Distribution transformers are among the assets whose failures pose the highest ignition risk.
(iii).B: Lessons Learned	Occurrences of poor data quality must be addressed to ensure prediction accuracy.
(iii).C: Quantitative Performance Metrics	• Percentage (%) of predictions that upon review warrant field investigation. Target: TBD

(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 206 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 an estimated overall effectiveness of 10%, which is correlated 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.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the model predicts a failed or 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 EPIC 3.20 analytics model will be integrated into the Asset Health and Performance Center asset monitoring workflow by using machine learning and automating the troubleshooting process of signal anomalies. When a failure is predicted, the asset will be flagged for review. Depending on findings of the review, PG&E may dispatch crews to inspect 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 informed decisions made by the Power Quality and Asset Health & Performance teams through the entire service territory.

7.1.D.3.13 EPIC 3.32: System Harmonics for Power Quality Investigation

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	
(i).C: 2020 WMP Section	5.1.D.3.16
(i).D: 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).E: Utility Wildfire Mitigation Maturity Model (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	Design/Engineering
(ii).B: Project Status	Team has issued a Purchase Order (PO) to meter hardware vendor. Expected lead time for the meters is 12-16 weeks. Team plans to identify meter locations and install meters in Q1 2021.
(ii).C: Project Location	Three phase commercial/industrial customer locations with a high number of DER/Solar PV and agriculture customers in the Central Valley region.
(iii).A: Results to Date	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 Q4 2020 • Issued PO to meter hardware vendor. • Kick-off project with IT.
(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.
(iii).C: Quantitative Performance Metrics	• Percentage (%) availability of harmonics data from installed meters. Target: ≥ 90% • Number (#) of hours to notification after harmonics levels meet analytical criteria. Target: ≤48 hours
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model:

	Estimated Potential Risk Reduction Score: 198 Risk Drivers: Equipment Failure Deployment Scope Assumption: 12,728 miles of distribution lines in Tier 2 & 3 HFTDs 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 an estimated overall effectiveness of 10%, which is correlated 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.
(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 is an analytics tool with the ability to monitor for, and enable proactive mitigation of, harmonics-related issues at approximately 3,000 large commercial customers throughout the service territory.

7.1.D.3.14 Sensor IQ

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Additional References in the 2021 WMP	7.3.2.2.4
(i).C: 2020 WMP Section	5.1.D.3.17
(i).D: 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 October 2021 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 (Rapid Earth Fault Current Limiter), 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).E: Utility Wildfire Mitigation Maturity Model (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 process of development, deployment and validation with the plan of full deployment to ~500K meters in Tier 2 & Tier 3 HFTDs by the end of 2021.
(ii).C: Project Location	~500K SmartMeter electric meters located in Tier 2 & Tier 3 HFTDs.
(iii).A: Results to Date	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.
(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%
(iii).D: Quantitative Risk Reduction Benefits	Sensor IQ is a foundational data collection project without its own Quantitative Risk Reduction Benefits. The 7.1.D.3.3 EPIC 3.15 Proactive Wires Down Mitigation Demonstration Project (Rapid Earth Fault Current Limiter), 7.1.D.3.12 EPIC 3.20 Maintenance Analytics, and 7.1.D.3.15 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.

7.1.D.3.15 EPIC 3.43: Momentary Outage Information

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	7.3.2.2.4
(i).C: 2020 WMP Section	N/A
(i).D: 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 as described in Section 7.1.D.15 above 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 AMI momentary events ("blinks") and trap alarms 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 initiative is underway to add field insight from two additional sources of information: a new generation smart meter/grid edge sensor, and a behind-the-meter 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 behind-the-meter electrical condition detection sensor provides an independent view of similar potential issues, but from the customer side of the meter.
(i).E: Utility Wildfire Mitigation Maturity Model (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 is waiting for deployment of Sensor IQ to commence data collection and analytic development. The second part of the project, related to the new generation meter and behind-the-meter electrical condition detection sensor, is being initiated. Vendors have been selected and contract negotiations are expected to complete in Q1 2021.
(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 meter and behind-the-meter electrical condition detection sensor are being piloted in a few Tier 2 & Tier 3 HFTDs.

(iii).A: Results to Date	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
(iii).C: Quantitative Performance Metrics	• Area Under the Precision/Recall Curve for each model developed, as applicable. Target: Positive value.
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 365 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 an estimated overall effectiveness of 10%, which is correlated 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.
(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 vegetation management, 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 new generation meter and the behind-the-meter 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 new generation, or the behind-the-meter electrical condition detection sensor would need to be installed in select 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

7.1.D.3.16 Wind Loading Assessments

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	7.3.3.13
(i).C: 2020 WMP Section	5.1.D.3.18
(i).D: 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 will reduce risk by providing asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds. The project will leverage existing LiDAR data from Vegetation Management (VM) efforts to geo-correct pole locations. Objectives of this project include 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 will be performed to identify the wind loading of each asset on a support structure with the objective of integrating findings into risk models.
(i).E: Utility Wildfire Mitigation Maturity Model (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	Build/Test
(ii).B: Project Status	Deployed the Wind Loading Assessment application to an initial group of 62 Distribution estimators
(ii).C: Project Location	PG&E service territory (PG&E owned distribution poles)
(iii).A: Results to Date	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 this project.
(iii).C: Quantitative Performance Metrics	Pass/fail criteria: • Accurate data for pole loading calculations. • Integration of data into an external cloud environment for greater accessibility. • Ability of a separate downstream project to perform pole geo-correction based on this project's LiDAR data.
(iii).D: Quantitative Risk Reduction Benefits	See the (iii).D: Quantitative Risk Reduction Benefits response item description above for an explanation of how PG&E's Enterprise Risk Model was applied to

	this project as well as references to relevant risk model materials in the 2021 WMP filing. The following Quantitative Risk Reduction Benefits have been determined using PG&E's Enterprise Risk Model: Estimated Potential Risk Reduction Score: 22 Risk Drivers: Equipment Failure Deployment Scope Assumption: System-wide This analytics project assumes the ability to detect issues with poles prior to failure. The risk mitigation potential is driven by an estimated overall effectiveness of 10%, which is correlated 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 is above and beyond existing maintenance replacement programs.
(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.
(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.

7.1.D.3.17 EPIC 3.03: Advanced Distribution Energy Resource Management System

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: Additional References in the 2021 WMP	
(i).C: 2020 WMP Section	5.1.D.3.20
(i).D: 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 (DIDF) 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 distributed energy resources (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: (1) increased situational awareness of DER grid impacts which could allow for greater operational flexibility to safely reconfigure the grid during PSPS; (2) decreased time to de-energize remote grid locations by utilizing the remote disconnect feature of DERMS for remote grids during PSPS events; and (3) 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).E: Utility Wildfire Mitigation Maturity Model (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	Factory acceptance testing for the gateway device to be installed at the first pilot site at Blue Lake Rancheria has been completed. Installation of headend server at PG&E has been completed. - Installation of the gateway device at the pilot site is scheduled for early 2021. The field deployment has experienced delays because the pilot site is involved in COVID-19 response with the recent surge in cases. Third-party site gateway vendors have begun interoperability testing with the headend server.
(ii).C: Project Location	Blue Lake Rancheria (BLR), Blue Lake, CA (Humboldt County). The BLR is a 100 acre tribal reservation and State-designated Disadvantaged Community (DAC).
(iii).A: Results to Date	• Completed design and installation of an IEEE 2030.5 DER Headend Server (CSIP certification pending) • Initial gateway buildout at the Blue Lake Rancheria site to test telemetry and control (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	Pass/fail criterion: • Ability to meet CPUC telemetry maximum cost and minimum functionality requirements for each DER site or DER aggregator.
(iii).D: Quantitative Risk Reduction Benefits	This project is foundational and therefore Quantitative Risk Reduction Benefits are not applicable. See the 7.1.D.3.5 Remote Grids and 7.1.D.3.6 EPIC 3.11 Multi-Use Microgrid projects for their Quantitative Risk Reduction Benefits that partially depend upon this foundational project.
(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 ADMS team (see Section 7.1.D.3.18 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.

7.1.D.3.18 Advanced Distribution Management System

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: Additional References in the 2021 WMP	8.1
(i).C: 2020 WMP Section	5.1.D.3.21
(i).D: Project Objective and Summary	PG&E is undertaking the first component of a multi-year effort to implement an Advanced Distribution Management System (ADMS) which will, when fully deployed, integrate into a single platform several of the current mission critical distribution control center applications (Distribution Supervisory, Control and Data Acquisition (DSCADA) software, Demand Management System (DMS), 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).E: Utility Wildfire Mitigation Maturity Model (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	Software is under development.
(ii).C: Project Location	Applicable to the entire PG&E electric distribution service territory
(iii).A: Results to Date	Q3 2020/Q4 2020 • Performing software build for wildfire mitigation functionality
(iii).B: Lessons Learned	None to date
(iii).C: Quantitative Performance Metrics	Pass/fail criterion: • 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).
(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 distribution control center applications that are currently spread across multiple platforms. This technology will enable the visibility, control, forecasting and analysis required from a more dynamic grid. When fully deployed, the ADMS platform will bring the capabilities of today’s Distribution Supervisory, Control and Data Acquisition (D-SCADA) software, DMS, and Outage Management System (OMS) into a single platform. 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.