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**BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, for a Permit to Construct the Fulton-Fitch Mountain Reconductoring Project (U 39 E)	Application No. A1512005

**APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY
FOR A PERMIT TO CONSTRUCT THE
FULTON-FITCH MOUNTAIN
RECONDUCTORING PROJECT**

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PACIFIC GAS AND ELECTRIC COMPANY

Dated: December 3, 2015

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APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR A PERMIT TO CONSTRUCT THE FULTON-FITCH MOUNTAIN RECONDUCTORING PROJECT

Pursuant to Section IX(B) of General Order ("GO") 131-D and Rules 2.1 through 2.5 and 3.1 of the California Public Utilities Commission's ("Commission" or "CPUC") Rules of Practice and Procedure, Pacific Gas and Electric Company ("PG&E") respectfully requests a Permit to Construct ("PTC") the Fulton-Fitch Mountain Reconductoring Project ("project") to improve transmission system reliability and capacity, and continue to provide safe and reliable electric service, for customers in Sonoma County.

I. PROJECT OVERVIEW

PG&E proposes to reinforce the electric transmission system in Sonoma County by replacing the conductor (reconductoring) on a 9.9-mile-long section of the Fulton-Hopland 60 kV Power Line (Fulton-Hopland Line) between the communities of Fulton and Healdsburg. The Fulton-Fitch Mountain Reconductoring Project will also include replacing poles along 8.1 miles of the Fulton-Hopland Line, removing the first pole and replacing the second pole of the Fitch Mountain #1 Tap 60 kV Power Line (Fitch Mountain #1 Tap), replacing conductor on 1.3 miles of the Geysers #12-Fulton 230 kV Transmission Line (Geysers #12-Fulton Line) to provide adequate spacing between lines, and making minor modifications to Fitch Mountain Substation. The current estimated cost of the project is $17.5 million.[1/]

PG&E owns and operates the Fulton-Hopland Line and the Fulton No. 1 60 kV Power Line (Fulton No. 1 Line), which serve electric customers in Sonoma County, including the communities of Healdsburg and Windsor. An outage on the Fulton No. 1 Line could overload the Fulton-Hopland Line above its re-rated summer emergency rating. The California Independent Systems Operator ("CAISO") has approved reconductoring the Fulton-Hopland Line to address this issue. (*See* Exhibit E, at 211; also 11, 66 and 71.)

II. REGIONAL CONTEXT AND PROJECT COMPONENTS

A. Regional Context

Fulton Substation serves an area that includes the communities of Fulton, Windsor, and Healdsburg (see Exhibit A, Project Overview Map). Power to the area originates in The Geysers, the world's largest geothermal field, located approximately 12 miles north of the project area in the Mayacamas Mountains. The point of interconnection for much of The Geysers' geothermal power generation is Fulton Substation, which also serves as a regional electric switching station. Fulton Substation includes 230 kV, 115 kV, and 60 kV switching and voltage transforming facilities, as well as 12 kV distribution transforming facilities.

Power from The Geysers geothermal field is carried to Fulton Substation by the double-circuit Geysers-Fulton 230 kV Transmission Line, which consists of the Geysers #12-Fulton and Geysers #17-Fulton circuits and provides electric service in southern Sonoma and Napa counties. Power is stepped down at Fulton Substation to either 115 kV or 60 kV, ~~depending on the destination.~~ Two 60 kV power lines – the Fulton No. 1 and the Fulton-

1/ This cost estimate is based upon a Class 4 estimate under the Association for the Advancement of Cost Engineering ("AACE") International's classification system, with an expected accuracy range of +50% to -30%.

Hopland lines – originate at and travel north from Fulton Substation. These lines provide electric power to the City of Healdsburg's Badger Substation and PG&E's Fitch Mountain and Geyserville substations.

Fitch Mountain Substation serves northern Windsor and the distribution facilities east and west of the City of Healdsburg. The substation is connected to the Fulton-Hopland Line to the east by Fitch Mountain #1 Tap; the Fitch Mountain #2 Tap connects the substation to the Fulton No. 1 Line to the west, creating a loop for system reliability. Geyserville Substation serves customers in the City of Geyserville and surrounding areas; once this project is completed, Geyserville Substation will be able to use the Fulton-Hopland Line as an alternate source of power during an outage on the Fulton No. 1 Line. The existing system will not be reconfigured as part of the project.

B. Project Components

The project includes the following major components:

1. Fulton-Shiloh Segment

The Fulton-Shiloh segment originates at an existing TSP located within Fulton Substation, at the southern end of the project. The existing Fulton-Hopland Line leaves the south side of Fulton Substation and follows the western and northern borders of Fulton Substation as underbuild on the same H-frame structures as the substation's 230 kV cap bank transmission line for approximately 0.3 mile, joining PG&E's double-circuit Geysers-Fulton 230 kV Transmission Line as underbuild on the same TSPs on the north side of the substation. The co-located lines cross Highway 101 in a northeasterly direction, and continue north on the west side of Lavell Road, across the street from Mark West Elementary School, for approximately 0.3 mile. The lines then continue overland for approximately 0.3 mile, crossing Deerwood Drive, Mark West Creek, and the Larkfield-Wikiup residential neighborhood. The lines cross Old Redwood Highway to parallel the east side of Faught Road for approximately 0.7 mile, crossing the joint campus of the San Miguel Elementary and Mark West Charter schools, then cross Faught Road where they turn east and parallel the north side of the road for approximately 0.2 mile. The Fulton-Shiloh segment terminates at an existing TSP in the southwest corner of Sonoma County's Shiloh Ranch Regional Park; the Geysers-Fulton 230 kV lines continue northeast.

In this segment, approximately 1.8 miles of the existing, single-circuit Fulton-Hopland Line will be reconductored. Additionally, to provide adequate spacing (clearance) between lines and structures, 1.3 miles of the Geysers #12-Fulton 230 kV line will be reconductored, one wood pole on a 12 kV distribution line along Old Redwood Highway will be relocated, and two street lights along Faught Road will be lowered or moved.

2. Shiloh-Fitch Segment

The Shiloh-Fitch segment begins at the existing TSP in the southwest corner of Shiloh Ranch Regional Park, where the 60 kV Fulton-Hopland Line splits off from the double-circuit Geysers-Fulton 230 kV Transmission Line. The Fulton-Hopland Line, now supported on its own, primarily-wood poles, travels north-northwest for approximately 1.3 miles, crossing Shiloh Ranch Regional Park and Shiloh Ridge Road, and skirting vineyards and rural residential areas. It continues in a northwesterly direction for approximately 1 mile, crossing Chalk Hill Road before climbing and following a ridgeline for approximately 0.7 mile. The line continues north-northwest for 2.6 miles, crossing vineyards, rangeland, and woodland, Foothill Oaks Regional Park, Windsor Creek, and Brooks Road, and entering Windsor Oaks Vineyards from the southwest. From here, the line heads northwest for one mile, crossing into Sotoyome Highlands from the south side. The line continues northwest for an additional 1.5 miles across rangeland to its interconnection with the Fitch Mountain #1

Tap on a ridge in the Minaglia Ranch just east of the City of Healdsburg, south of the Russian River and Bailhache Avenue.

In this segment, approximately 8.1 miles of the existing, single-circuit Fulton-Hopland Line will be replaced. To support the new conductors, existing poles will either be replaced with taller LDS poles or TSPs, or removed. The first pole on the Fitch Mountain #1 Tap will be removed, and the second pole will be replaced with a taller LDS pole.

3. Substation Modifications

Fitch Mountain Substation is located at 195 Bailhache Avenue in unincorporated Sonoma County, east of Healdsburg, on an approximately 1-acre parcel. The substation is bordered on the north and west by a mineral resource processing plant, and on the east and south by rural residential areas. Certain facilities will be replaced and upgraded at Fitch Mountain Substation to handle the higher-rated conductor on the Fulton-Hopland Line.

III. THE APPLICANT

Since October 10, 1905, PG&E has been an operating public utility corporation, organized under the laws of the State of California. PG&E is engaged principally in the business of furnishing gas and electric service in California. PG&E's principal place of business is 77 Beale Street, San Francisco, California, 94105.

Communications with regard to this Application should be addressed to:

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Incorporated herein by reference is a certified copy of PG&E's Articles of Incorporation, effective April 12, 2004, which was filed with the Commission in connection with PG&E's Application No. A.04-05-005 on May 3, 2004.

A copy of PG&E's most recent proxy statement dated March 25, 2015, was filed with the Commission as part of Application 15-05-016. Copies of PG&E's most recent financial statements (contained in the Form 10-Q Quarterly Report filed on October 28, 2015, by PG&E Corporation and Pacific Gas and Electric Company, for the period ending September 30, 2015) are attached as Exhibit F.

IV. ADDITIONAL INFORMATION REQUIRED BY SECTION IX(B) OF GO 131-D:

Pursuant to Rule 2.4 (b) of the Commission's Rules of Practice and Procedure, PG&E has submitted a PEA, which is attached as Exhibit B to this Application. The following information is required by Section IX.B of GO 131-D:

a. *A description of the proposed power line and substation facilities, including the proposed power line route; proposed power line equipment, such as tower design and appearance, heights, conductor sizes, voltages, capacities, substations, switchyards, etc., and a proposed schedule for authorization, construction, and commencement of operation of the facilities.*

A detailed description of the proposed project, route, and components is contained in Section II.B above and in Chapter 2 of the PEA, Exhibit B. A Preliminary Project Schedule is attached as Exhibit C.

b. *A map of the proposed power line routing or substation location showing populated areas, parks, recreational areas, scenic areas, and existing electrical transmission or power lines within 300 feet of the proposed route or substation.*

A project map showing the project route and substation location is attached as Exhibit A. Maps showing the populated areas and parks (which are also recreational areas) near the project alignment as well as existing power lines within 300 feet of the project are provided in Chapter 2 and Chapter 3 of the PEA, Exhibit B (*see* Figures 2.0-1, 2.0-2, 3.10-1, and 3.10-2). There are no scenic areas near the alignment.

> c. *Reasons for adoption of the power line route or substation location selected, including comparison with alternative routes or locations, including the advantages and disadvantages of each.*

As discussed in Chapter 2 of the PEA, Exhibit B, this project consists of reconductoring an existing power line, so the discussion of routing issues required in GO 131-D, Section IX.B.1.c, is not applicable to this application.

> d. *A listing of the governmental agencies with which proposed power line route or substation location reviews have been undertaken, including a written agency response to applicant's written request for a brief position statement by that agency. (Such listing shall include The Native American Heritage Commission, which shall constitute notice on California Indian Reservation Tribal governments.) In the absence of a written agency position statement, the utility may submit a statement of its understanding of the position of such agencies.*

United States Army Corps of Engineers: On September 21, 2012, PG&E staff met with Jim Mazza from the United States Army Corps of Engineers ("USACE") as well as representatives from the Central Coast Regional Water Quality Control Board ("CCRWQCB") and the California Department of Fish and Wildlife ("CDFW"). At that meeting PG&E representatives described the project, including potential impacts to waters of the United States. Mr. Mazza recommended that all waters be included in a Pre-Jurisdictional Determination, which PG&E agreed to submit.

Central Coast Regional Water Quality Control Board: As part of early project planning efforts, on September 21, 2012, PG&E staff met with Steve Bargsten from the CCRWQCB as well as representatives from CDFW and USACE. At that meeting, PG&E representatives described the project, including potential impacts to waters of the state. No particular concerns were expressed.

<u>California Department of Fish and Wildlife</u>: As part of early project planning efforts, PG&E staff met on September 21, 2012 with Laurie Hammerli from CDFW as well as representatives from CCRWQB and USACE. At that meeting, PG&E representatives described the project, including potential impacts to waters of the state. Ms. Hammerli asked PG&E to prepare a Streambed Alteration Agreement notification to determine if work will require an Agreement.

<u>Native American Heritage Commission ("NAHC")</u>: As part of the consultation process with Native American organizations and individuals, PG&E's project consultant contacted the NAHC by letter on June 8, 2011, with a request for information about sacred lands that may be located within the project area and a list of interested Native American groups and individuals near the project area. A search of the Sacred Lands file housed at the NAHC indicated a single resource listed on the Native American Sacred Lands Inventory, described as a Sacred Power Site. The NAHC provided a list of local groups and individuals to contact for further information regarding local knowledge of sacred lands. Letters and associated maps were sent on June 10, 2011, to the individuals from these local groups. Follow-up emails were sent on June 29, 2011. Following the addition of new project components, the tribes were again contacted by email (and in some cases by phone and letter) on November 20, 2012 and September 24, 2015. In a letter dated July 18, 2011, the Federated Indians of Graton Rancheria stated that they do not believe that the project will adversely impact their cultural resources; in a letter dated July 1, 2015, the tribe designated a lead contact for receiving notices of proposed projects under AB-52; and, in an email dated October 21, 2015, the tribe requested additional information for SON-1256.

Sonoma County: On October 5, 2015, PG&E met with Sonoma County staff to provide them with an overview of the project. County staff members included Bert Whitaker, Director of County Parks, and Reg Cullen, representing the Permit and Resource Management Department. At this meeting, PG&E described the need for the project and discussed construction-related issues related to the County of Sonoma and its residents, including impacts to parks and work in County right-of-way. Additionally, the need for PG&E to obtain encroachment permits from the County was discussed. In response to a request for a position statement, PG&E received an email statement from Mr. Cullen confirming the meeting with PG&E and indicating that County staff was prepared to work with PG&E to process any encroachment and/or other permits required for the project.

V. MEASURES TAKEN TO REDUCE EMF EXPOSURE

Section X(A) of GO 131-D requires that applications for a PTC include a description of the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields ("EMF") generated by the proposed facilities. In accordance with Section X(A) of GO 131-D, CPUC Decision No. D.06-01-042 ("EMF Decision"), and PG&E's EMF Design Guidelines prepared in accordance with the EMF Decision, PG&E is required to prepare a Field Management Plan ("FMP") that identifies the "no-cost" and "low-cost" magnetic field reduction measures proposed as part of the final engineering design for the project.

The FMP developed in support of the Fulton-Fitch Mountain Reconductor Project considered raising the height of six poles in the school land use area by ten feet. However, the estimated cost of removing and replacing six poles with taller poles in the school land use area would be approximately $3,597,871, or approximately 21 percent of estimated total project cost, which substantially exceeds the low cost 4% benchmark. As a result, this option was rejected. No other low-cost measures are available for this project. A copy of the Field Management Plan for this project is attached as Exhibit D.

VI. PUBLIC NOTICE

Pursuant to Section XI(A) of GO 131-D, notice of the Application will be sent to Sonoma County Planning and Development Services Department, the Town of Windsor Planning Services Department, the City of Healdsburg Planning and Building Services Department, the California Energy Commission, the State Department of Transportation and its Division of Aeronautics, the Secretary of the Resources Agency, the California Department of Fish and Wildlife, the Department of Public Health, the State Water Resources Control Board, the California Air Resources Board, the Bay Area Air Quality Management District, Northern Sonoma County Air Pollution Control District, Central Coast Regional Water Quality Control Board, the NAHC, the State Department of Transportation's District Office, the United States Fish and Wildlife Service, United States Army Corps of Engineers, all owners of land within 300 feet of the proposed project (as determined by the most recent local assessor's parcel roll available to PG&E at the time the notice is sent), and any other interested parties that have requested such notification.

In accordance with Section XI(A)(2), within ten days after filing the Application, PG&E will publish a notice of the Application once a week for two successive weeks in the Santa Rosa Press Tribune newspaper. In accordance with Section XI(A)(3), PG&E will also post a notice of the Application on-site and off-site where the proposed project is located. PG&E will deliver a copy of the notice to the CPUC Public Advisor and the CPUC's Energy Division in accordance with Section XI(A)(3), and will file a declaration of mailing and posting with the Commission within five days after completion.

VII. REQUEST FOR TIMELY ACTION

To enable PG&E to secure necessary permits from other agencies and property rights from landowners, and begin construction by summer of 2018 or sooner as set forth in Exhibit C, PG&E's Preliminary Project Schedule, PG&E respectfully requests that this Application be approved no later than February of 2017.

VIII. EXHIBITS

The following exhibits are attached and incorporated by reference to this Application:

Exhibit A: Project Overview Map

Exhibit B: Proponent's Environmental Assessment ("PEA")

Exhibit C: Preliminary Project Schedule

Exhibit D: EMF Field Management Plan

Exhibit E: Excerpts from the 2009 California ISO Transmission Plan

Exhibit F: PG&E's Financial Statement from the latest Form 10-Q Quarterly Report

IX. CONCLUSION

PG&E respectfully requests that the Commission:

1. Issue a Decision and Order, effective immediately, granting PG&E a Permit to Construct the Fulton-Fitch Mountain Reconductoring Project, adopting an appropriate environmental document for the project, and granting any other permission and authority necessary to construct, operate and maintain the project.

2. Authorize Energy Division to approve requests by PG&E for minor project modifications that may be necessary during final engineering and construction of the project so long as Energy Division finds that such minor project modifications would not result in new significant environmental effects or a substantial increase in the severity of previously identified significant effects.

3. Grant such other and further relief as the CPUC finds just and reasonable.

Dated in San Francisco, California, this 3rd day of December, 2015.

Respectfully submitted,

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By: */s/ JO LYNN LAMBERT*
JO LYNN LAMBERT

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PACIFIC GAS AND ELECTRIC COMPANY

SCOPING MEMO INFORMATION

Category:

Ratesetting. Pursuant to Rule 2.1(c) of the Commission's Rules of Practice and Procedure, the application must propose a category for the proceeding as defined in Rule 1.3. If none of the enumerated categories are applicable, proceedings will be categorized under the catch-all "ratesetting" category. (CPUC Rule 7.1 (e)(2).) The Commission has consistently found that applications for CPCNs and PTCs under GO 131-D do not fit within any of the enumerated categories and should therefore be considered as "ratesetting proceedings."

Need for hearing:

The CPUC has determined that issues related to project need and cost are not within the scope of PTC applications, leaving only environmental review as a relevant issue. No areas of environmental or other public concern are known. If concerns about the project are raised, PG&E recommends that a public participation hearing be held.

Issues:

None known.

Proposed Schedule:

See Exhibit C, attached.

VERIFICATION

I, the undersigned, declare:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on November 17, 2015, at San Francisco, California.

/s/ ANDREW WILLIAMS

Andrew Williams

Vice President, Safety, Health and Environment

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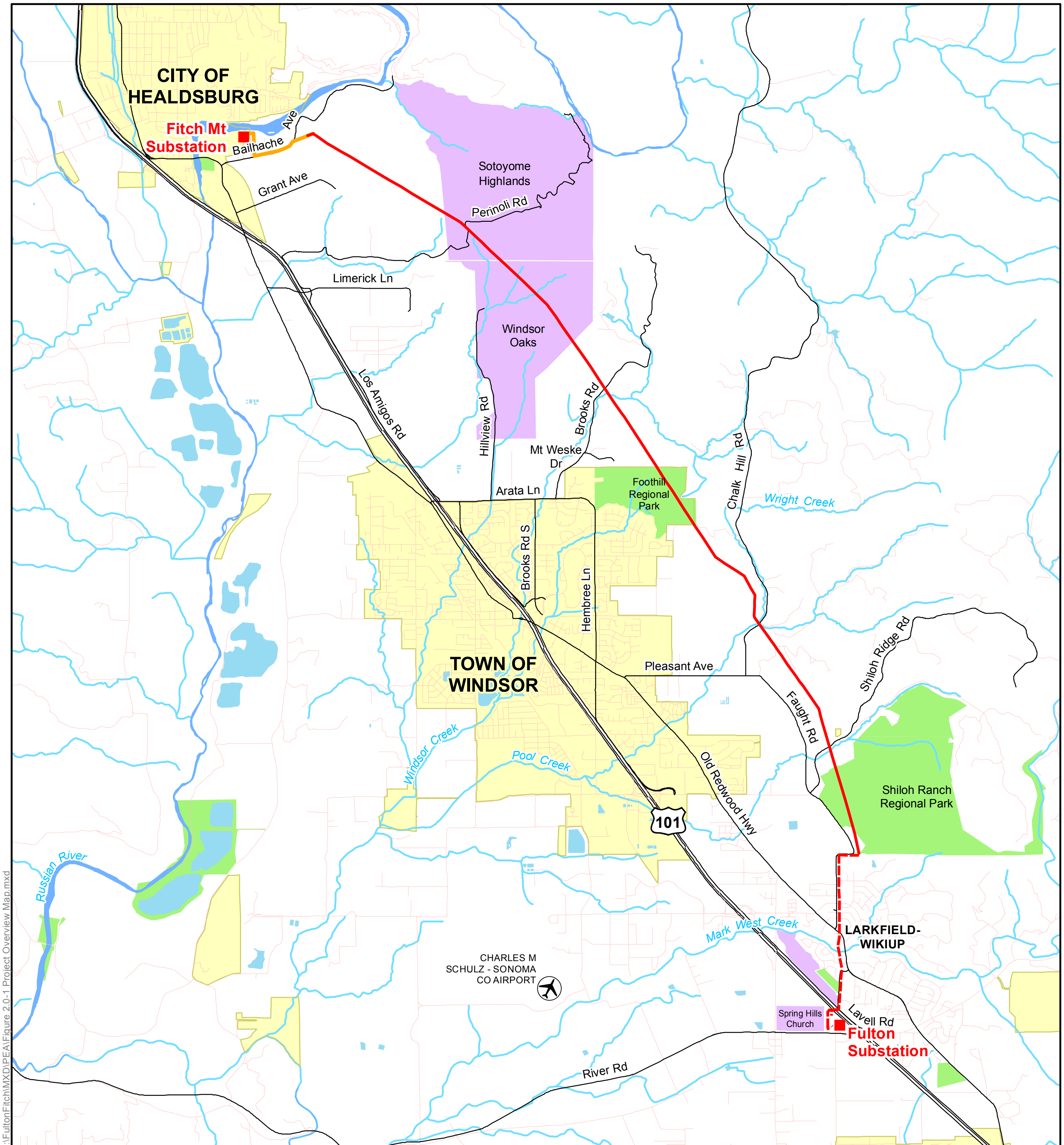
Exhibit A

Project Overview Map



- Substation
- Shiloh-Fitch Segment
- Fulton-Shiloh Segment
- Fitch Mountain #1 Tap
- Conservation Easement
- Regional Park
- City Limits

Project Overview Map

Fulton-Fitch Mountain Reconductoring Project

1:75,000

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PG&E

11/20/2015

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Exhibit B

Proponent's Environmental Assessment ("PEA")

The PEA is too voluminous to be filed electronically
and therefore is being submitted either in the form of an archival-grade DVD
or on CD-Rom.

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Exhibit C

Preliminary Project Schedule

Exhibit C

FULTON-FITCH MOUNTAIN RECONDUCTORING PROJECT
PRELIMINARY PROJECT SCHEDULE

PTC Application submitted	December 3, 2015
Protests and notice of deficiencies, if any	January 3, 2016
Response to any protests, deficiencies	February 3, 2016 or sooner
Application complete	April 15, 2016
Draft Mitigated Negative Declaration (MND) released	July 15, 2016
Close of Public Review Period	August 15, 2016
Mitigated Negative Declaration (MND) adopted per CEQA requirements (no later than 180 days from complete application per CEQA Guidelines § 15107)	October 15, 2016
Requested date by which MND Adopted and PTC Decision Approved and Effective	February 2017
Acquisition of other required permits	June 2016 – June 2018
Acquisition of land rights as needed	November 2016 – June 2017
Materials Procurement	Spring 2017 – June 2018
Initial Notice to Proceed / Construction Begins	Summer 2018 or sooner if possible
Project Operational	March 2019

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Exhibit D

EMF Field Management Plan

I. General Description of Project

Project Lead: Project Manager, Electric Transmission Maintenance and Construction

Transmission Line: Fulton-Hopland 60 kV line
Geysers #12-Fulton 230 kV line

Distribution line Underbuild: None.

Scope of Work:

The Fulton-Fitch Mountain project was put in place to increase line capacity and reliability. Approximately 9.9 miles of the Fulton-Hopland 60kV line, and 1.3 miles of the Geysers #12-Fulton 230kV/Fulton 230kV line will be reconductored. We are replacing the mostly-wood poles with LDSPs and TSPs on the Fulton-Hopland line.

Base Cost of Project: Approximately $17,500,000

Four percent of this estimated total cost is $700,000.

II. BACKGROUND: CPUC DECISION 93-11-013 AND EMF POLICY

On January 15, 1991, the CPUC initiated an investigation to consider its role in mitigating the health effects, if any, of electric and magnetic fields from utility facilities and power lines. A working group of interested parties, called the California EMF Consensus Group, was created by the CPUC to advise it on this issue. It consisted of 17 stakeholders representing citizens groups, consumer groups, environmental groups, state agencies, unions, and utilities. The Consensus Group's fact-finding process was open to the public, and its report incorporated concerns expressed by the public. Its recommendations were filed with the Commission in March 1992.

Based on the work of the Consensus Group, written testimony, and evidentiary hearings, the CPUC issued its decision (93-11-013) on November 2, 1993, to address public concern about possible EMF health effects from electric utility facilities.

In response to a situation of scientific uncertainty and public concern, the decision specifically requires PG&E to consider "no-cost" and "low-cost" measures, where feasible, to reduce exposure from new or upgraded utility facilities. It directs that no-cost mitigation measures be undertaken, and that low-cost options, when they meet certain guidelines for field reduction and cost, be adopted through the project certification process. PG&E was directed to develop, submit and follow EMF guidelines to implement the CPUC decision. Four percent of total project budgeted cost is the benchmark in implementing EMF mitigation, and mitigation measures should achieve incremental magnetic field reductions of at least 15%.

III. ELECTRIC AND MAGNETIC FIELDS (EMF)

EMF is a term used to describe electric and magnetic fields that are created by electric voltage (electric field) and electric current (magnetic field). Power frequency EMF is a natural consequence of electrical circuits, and can be either directly measured using the appropriate measuring instruments or calculated using appropriate information.

Electric fields are present whenever voltage exists on a wire, and are not dependent on current. The magnitude of the electric field is primarily a function of the configuration and operating voltage of the line and decreases with the distance from the source (line). The electric field can be shielded (i.e., the strength can be reduced) by any conducting surface, such as trees, fences, walls, buildings, and most types of structures. The strength of an electric field is measured in volts per meter (V/m) or kilovolts per meter (kV/m).

Magnetic fields are present whenever current flows in a conductor, and are not dependent on the voltage of the conductor. The strength of these fields also decreases with distance from the source. However, unlike electric fields, most common materials have little shielding effect on magnetic fields.

The magnetic field strength is a function of both the current on the conductor and the design of the system. Magnetic fields are measured in units called Gauss. However, for the low levels normally encountered near electric utility facilities, the field strength is expressed in a much smaller unit, the milliGauss (mG), which is one thousandth of a Gauss.

Power frequency EMF are present wherever electricity is used. This includes not only utility transmission lines, distribution lines, and substations, but also the building wiring in homes, offices, and schools, and in the appliances and machinery used in these locations. Magnetic field intensities from these sources can range from below 1 mG to above 1,000 mG (1 Gauss).

Magnetic field strengths diminish with distance. Fields from compact sources (i.e., those containing coils such as small appliances and transformers) drop off with distance "r" from the source by a factor of $1/r^3$. For three-phase power lines with balanced currents, the magnetic field strength drops off at a rate of $1/r^2$. Fields from unbalanced currents, which flow in paths such as neutral or ground conductors, fall off inversely proportional to the distance from the source, 1/r. Conductor spacing and configuration also affect the rate at which the magnetic field strength decreases, as well as the presence of other sources of electricity. The magnetic field levels of PG&E's power lines will vary with customer demand.

Magnetic field strengths for typical transmission power line loads at the edge of rights-of-way are approximately 10 to 90 mG.

IV. General Description of Surrounding Land Uses

Schools or Daycare: Six Poles (024/105, 024/106, 024/107, 025/113, 025/114 & 025/115).

Residential: Five poles.

Commercial/Industrial: Twelve poles.

Recreational: Nine poles.

Undeveloped Land and/or Agricultural, Rural: Sixty-nine poles.

V. No Cost and Low Cost Magnetic Field Mitigation

No Cost Field Reduction

There are no feasible no cost field reduction measures that can be implemented on this project.

Priority Areas where Low Cost Measures are to be Applied

Six poles in the school land use area are considered of magnetic field reduction.

Mark West Elementary School, 4600 Lavell Road, Santa Rosa, CA, 95403

San Miguel Elementary School, 5350 Faught Road, Santa Rosa, CA, 95403

Low Cost Magnetic Field Reduction Options

This FMP proposes to raise the height of six poles in the school land use area by ten feet taller.

Estimated cost to raise the height of six poles in the school land use area by ten feet taller is $3,597,871 (21 percent of estimated total project cost). Raising the height of six poles in the school land use area exceeds the low cost 4% benchmark.

No other low cost mitigation is available for this project.

VI. Conclusion - Field Reduction Options Selected

No low cost mitigation is available for this project.

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Exhibit E

Excerpts from the 2009 CAISO Transmission Plan

California ISO
Your Link to Power

2009 California ISO Transmission Plan

Department of Market and Infrastructure Development

Amended - June 2009

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Chapter 1: Background and Overview of the 2009 Transmission Plan

The ISO must under national industry standards annually assess the reliability of the transmission network under its control. This effort includes identifying the short- term need for grid upgrades and developing a long-term infrastructure vision that incorporates state and federal policy initiatives.

2008 was a watershed year for conducting important ISO transmission planning functions, which included launching the revised Transmission Planning Process (TPP) that meets FERC Order No. 890 directives, as well as conducting planning studies that will provide the basis for the 2010 Study Plan being developed with stakeholders. The ISO will use the 2009 Transmission Plan as part of the documentation used to demonstrate compliance with the NERC reliability standards that are applicable to the ISO as a Planning Coordinator. As such, this document contains the ISO's planning analysis results as well as providing some thoughtful insight on key issues important to the upcoming planning cycle.

This plan concludes the transmission planning activities that took place throughout 2008 and the first quarter of 2009. Because the planning process spans fifteen months, each Transmission Plan (and the associated Study Plan) is named for the year in which it is presented to the ISO Board of Governors. However, the planning process stages take place in the prior year and into the first quarter of the subsequent year. Thus, the 2010 TPP begins in January 2009 with studies and study assumptions that were submitted through the 2008 Request Window feeding into the 2009 TPP, which will culminate in a 2010 Transmission Plan. For the purposes of clarification, the study cycles will be identified for the calendar year in which they take place (*e.g.* the studies described in Chapter 1 took place in 2008; the upcoming studies described in Chapter 2 will take place in 2009).

This amended transmission plan report contains updated information regarding the projects that the ISO indicated it needs more time for their evaluations. Since the Plan was posted, the ISO was able to complete its evaluation of 13 projects as shown on pages 298-303 of this report.

Finally, this chapter presents the background and overview of the plan's development that is necessary to place the study results in context with the disposition of project proposals submitted through the 2008 Request Window and evaluated in 2008. This Chapter also defines the framework for the Chapter 2 description of studies to be conducted in the 2009 planning cycle.

1.1 Development of the Transmission Plan

The ISO developed the 2009 Transmission Plan in accordance with TPP requirements as highlighted below.

1.1.1 Compliance with FERC Order 890

In Order No. 890, federal regulators found that a lack of coordination, openness and transparency could result in opportunities to exercise undue discrimination in transmission planning. The order directed the ISO to develop and propose a coordinated process that complied with nine planning principles, which the ISO filed with the commission in December 2007. In June 2008, commissioners conditionally accepted the filing but they asked for a small number of clarifications and modifications, including tariff changes regarding comparability and the relationships between the ISO and its participating transmission owners. The ISO submitted its revised Transmission Planning Process Business Practice Manual and associated tariff changes on October 31, 2008.[1]

[1] Find more information at http://www.caiso.com/2074/20746fe93ce50.pdf. For more information regarding the Transmission Planning Process BPM, please refer to http://www.caiso.com/2024/20246de967b0.pdf.

1.1.2 The ISO Transmission Planning Process (TPP)

1.1.2.1 TPP Stages

The planning process consists of overlapping planning cycles beginning with the development of the study outline, as well as a process to reach consensus with stakeholders on the Unified Planning Assumptions. That effort is followed by conducting reliability and/or economic (congestion) studies performed by the ISO or under its supervision, which makes up the Transmission Plan.[2]

Specifically, the planning process consists of a Request Window and three stages:

- Request Window (August 15 – November 30):

Developers respond to identified grid needs by submitting all reliability and economic projects, Location Constrained Resource Interconnection Facility additions or upgrades, requests for economic planning studies and resource alternative proposals through the Request Window.

- Stage 1 (January – April): Identification of Unified Planning Assumptions and development of the Study Plan
- Stage 2 (May – November): Performance of technical analyses, posting of study results, and the proposed mitigation plans

The ISO posts its study results in September, which include noting reliability and economic transmission needs, as well as proposed mitigation solutions if necessary. Transmission owners provide their study results and propose projects in October.

- Stage 3 (December – March): Project approval and development of the ISO Transmission Plan

Based on study results, the ISO identifies projects to recommend for either ISO executive management or ISO Board approval, depending on cost thresholds as noted in the tariff, and posts a draft Transmission Plan by February. The ISO Board receives the final plan in March including *all* projects.

1.1.2.2 TPP Public Participation

The annual process includes holding at least three noticed public meetings, although more may be scheduled. The ISO welcomes written comments from stakeholders and then responds to them in the documents produced during each stage of the planning cycle.

During 2008, a meeting to discuss the Unified Planning Assumptions was held on March 10, 2008 followed by a second public meeting on November 20, 2008 to discuss the ISO study results. In addition, a public meeting to address the draft 2009 Transmission Plan was held on February 27, 2009, and comments were submitted on March 13, 2009. A matrix of these comments and responses is in Appendix C.

1.1.3 2009 Study Plan and Technical Studies Overview

The ISO completed the 2009 Transmission Study Plan in July 2008.[3] In accordance with the BPM requirements, the plan defined the scope and purpose of the following studies deemed necessary to conduct during the planning cycle:

- Reliability Assessments
- Local Capacity Requirements (LCR) studies

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[2] A flow diagram depicting the stages of the TPP is attached as Appendix D

[3] http://www.caiso.com/1f80/1f809d7723f70.pdf

- Generation and Import Deliverability studies
- ISO Short-term Congestion and Reliability Studies
- Long-Term Congestion Revenue Rights
- Renewable Resource Integration
- Other studies that required separate stakeholder processes such as Large Transmission projects

The ISO performed the studies, or directed the transmission owners to perform studies, as described in the BPM. As noted above, the ISO presented the Stage 2 preliminary study results to stakeholders November 20, 2008.

During Stage 3, the ISO reviewed projects proposed through the 2008 Request Window against the study results to determine whether they presented feasible solutions for identified needs. In addition, the ISO presented studies to be conducted during 2009 for the next study cycle.

1.1.4 Transmission Plan BPM Requirements

The ISO's Transmission Plan is the primary product of the planning process. Produced annually, it presents detailed information on newly proposed transmission projects and alternatives within the ISO's Balancing Authority Area as well as external transmission facilities that will interconnect with to the ISO controlled grid. While these requirements are more clearly articulated in the BPM, in general, the following information is provided in the 2009 Plan:

- Details and lists of transmission projects that were considered as part of the 2009 planning process;
- Information on future system conditions to facilitate transmission planning decisions;
- Results from technical studies performed by the ISO that focus on different perspectives of the system;
- Conclusions from analyses, potential concerns, potential grid enhancements, and plans for enhancing future iterations of the transmission plan

The following sections summarize the results of studies performed during Stage 2 as well as the project evaluations completed as part of Stage 3.

1.2 Request Window Submissions

1.2.1 Description of Submissions

The ISO's planning process uses a "Request Window" to provide transmission planning participants with the opportunity to submit proposals for consideration in the following year's planning cycle. All transmission project proposals seeking ISO approval must be submitted through the Request Window for evaluation during Stage 3 of the planning process. The BPM describes the types of proposals which the ISO normally expects to receive through the Request Window, as follows:

- Reliability-driven proposed upgrades or additions;
- Merchant facilities;
- Economic transmission projects based on economic efficiency and intended to mitigate ISO-identified congestion;
- Location constrained resource interconnection facilities;
- Projects to preserve long-term congestion revenue rights;
- Demand response programs;

- Generation projects submitted as proposed solutions along with economic study requests;
- Network upgrades identified through SGIP/LGIP; and
- Economic planning study requests

While the BPM describes the Request Window as opening on August 15 and closing on November 30 of each planning cycle, the 2008 Request Window timeframe was extended to December 15 because of the timing of the ISO October 31, 2008 Order No. 890 compliance filing. This one-time extension was provided to ensure that transmission planning participants had adequate time to submit their proposals into the transmission planning process.

At the close of the 2008 Request Window, the ISO received a total of 134 submissions. A summary of proposal type is listed below:

- One merchant transmission expansion project by a non-transmission owner;
- Two LCRIF projects submitted in the SCE service area proposed by SCE;
- Eleven projects submitted by non-transmission owners proposing equipment rental arrangements, with transmission owners, as mitigation solutions for reactive support deficiencies;
- A total of 104 PTO requests for reliability transmission upgrades and additions;
- One reliability project from a non-PTO
- One generation project submitted by a non-transmission owner as a reliability solution;
- Eight economic transmission projects; seven proposed by non-transmission owners and two proposed by a transmission owner.
- Five network upgrade projects identified by transmission owners through the LGIP/SGIP;
- Zero requests for economic studies; and
- One load interconnection project

Of the 134 projects received, eight were withdrawn before the ISO conducted its project evaluations, leaving a total of 126 proposals that are discussed below. All of the eight projects subsequently withdrawn were PTO-proposed reliability projects.

1.2.2 Disposition of Request Window Submissions

But for the variances described in this plan, the process by which Request Window proposals were addressed is described in BPM Sections 3 and 4.3 of the BPM. In general, all proposals were initially screened by the ISO to confirm that the submissions were data sufficient. Proposals failing this review were denied and additional information was requested from the project sponsor. Proposals passing the screening were evaluated using the Request Window evaluation process outlined in BPM Chapter 3 in which the ISO categorizes the proposals and determines which one proceed into the project approval process and which proposals would be carried forward into the 2009 study cycle.

1.2.3 Projects Eligible for Approval Recommendation in the 2009 Transmission Plan

51 proposals passed the ISO screening process and were reviewed by ISO Executive Management. Of these, two proposals, submitted under the ISO's location constrained resource interconnection tariff requirements, have potential capital costs greater than $50 million and will be presented to the ISO Board during the second quarter of 2009 if the commercial interest thresholds have been met. ISO Executive Management approved 45 proposals as being responsive to system reliability needs; representing approximate combined construction costs of more than $390 million. Four projects were denied approval. Tabular summaries of these projects are included in Table 1-1 and Table 1-2.

Table 1-1 Projects Eligible for Approval by ISO Executive Management

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date
1	Humboldt 115/60 kV Transformer Replacements	PG&E	Humboldt	Overloads under various B and C contingencies	Dec-10
2	Maple Creek Reactive Support	PG&E	Humboldt	Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek, and Hoopa 60 kV	May-11
3	Garberville Reactive Support	PG&E	Humboldt	Bridgeville, Fruitland, Fort Seward, Garberville, Kekawaka, Laytonville, Covelo 60 kV	May-11
4	Fulton-Fitch Mountain 60 kV Line Reconductor	PG&E	North Coast/Bay	Mitigate overload following the outage of L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	May-13
5	Clear Lake 60 kV System Reinforcement	PG&E	North Coast/Bay	Overloads and low voltages at several 60 and 115 kV substations in the areas under various B and C contingencies	May-12
6	Lakeville No. 2 60 kV Switch Upgrade	PG&E	North Coast/Bay	Overload of Lakeville 60kV #2	May-10
7	Glenn #1 60 kV Reconductoring	PG&E	North Valley	Overloads under various category B and C contingencies	May-13
8	Palermo 115 kV Circuit Breaker & Switch Replacement	PG&E	North Valley	Mitigate NERC category B (G-1/L-1) criteria violation and contributes to LCR reduction	May-10
9	Gold Hill-Horseshoe 115 kV Reinforcement	PG&E	Central Valley	Overloads under normal and emergency (B, C) conditions	May-11

4.5.2 North Coast and North Bay area

The North Coast area is located north of the Bay Area and south of the Humboldt area along the northwest coast of California. It extends from Laytonville in the north to Petaluma in the south. The North Coast area has both coastal and interior climate regions covering an area of approximately 10,000 square miles with a population of approximately 800,000 people in Sonoma, Mendocino, Lake and a portion of Marin counties. Projection of demand in North Coast is expected to reach 833 MW in 2011 with the growth rate of approximately 1.6% per year. A significant amount of North Coast generation is from geothermal (The Geysers) resources. The figure on the left depicts the approximate geographical location of the North Coast and North Bay area.

North Bay encompasses the area just north of San Francisco. This transmission system serves the counties of Marin, Napa and portions of Solano and Sonoma Counties. Novato, San Rafael, Vallejo and Benicia are among the cities PG&E provides electric service to within this area. North Bay's electric transmission system is comprised of 60, 115, and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento, and Bay Area. The forecast for load growth in the North Bay area is approximately 1.5% and is expected to reach 750 MW by 2011.

4.5.2.1 Area-specific assumptions and system conditions

The North Coast and North Bay area study was performed consistent with the general study assumptions and methodology described in Chapter 3 and Appendix A. The ISO secured website lists the contingencies that were performed as part of this assessment. In addition, specific assumptions and methodology applied to the North Coast and North Bay area studies are provided in this section.

Generation

Generation resources in North Coast and North Bay areas consist of market, QFs and self-generating units. Table 4-8 lists generating plants in the North Coast and North Bay areas.

Load forecast

Loads within the North Coast and North Bay areas reflect a coincident peak load for 1-in-10-year heat wave conditions of each study scenario. Tables 4-9 show load level in the base case under summer peak conditions.

Table 4-8: Generator in North Coast and North Bay areas

Generation Plants	Max. Capacity (MW)
Bottle Rock	55
Potter Valley	7.2
Bear Canyon	20
Geo Energy	20
Geysers 11	64
Gersers 12	52
Geysers 13	61
Geysers 14	49
Geysers 16	56
Geysers 17	52
Geysers 18	47
Geysers 20	42
Geysers 7	34
Geysers 8	34
Geysers 5	40
Geysers 6	40
Indian Valley	1.6
Monticello	5.7
NCPA Unit 1	67
NCPA Unit 2	62
Santa Fe	160
Smud Geo	41
Sonoma Landfill	4.7
Westford Flat	30
Generation Total	**1045**

Table 4-9: Summer peak load forecasts modeled in North Coast and North Bay area assessments

	MW Load Forecast										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Humboldt	131	132	134	136	138	140	142	144	145	147	149
North Coast	843	857	870	884	899	913	927	941	954	968	981
North Valley	761	772	784	799	816	829	842	855	868	881	894
Sacramento	1,025	1,037	1,049	1,064	1,076	1,089	1,101	1,114	1,127	1,139	1,152
Sierra	1,025	1,054	1,082	1,114	1,147	1,176	1,206	1,235	1,264	1,293	1,322
North Bay	748	755	764	774	783	793	803	812	822	832	841
East Bay	914	920	927	934	941	948	955	962	969	975	982
Diablo	1,627	1,644	1,662	1,684	1,704	1,723	1,742	1,761	1,780	1,798	1,817
San Francisco	912	920	928	938	947	956	965	974	983	992	1,002
Peninsula	994	1,011	1,023	1,033	1,041	1,055	1,069	1,083	1,096	1,110	1,123
Stockton	1,309	1,327	1,347	1,371	1,394	1,416	1,438	1,461	1,483	1,505	1,527
Stanislaus	221	228	233	238	244	249	254	258	263	268	273
Yosemite	795	805	817	828	839	851	862	874	886	898	909
Fresno	1,986	2,013	2,040	2,072	2,104	2,132	2,159	2,187	2,215	2,242	2,269
Kern	1,401	1,422	1,444	1,467	1,491	1,513	1,535	1,557	1,580	1,601	1,623
Mission	1,258	1,270	1,281	1,295	1,307	1,320	1,333	1,346	1,359	1,371	1,384
De Anza	919	927	936	946	956	966	977	987	998	1,008	1,018
San Jose	1,713	1,734	1,754	1,771	1,789	1,810	1,831	1,853	1,875	1,895	1,916
Central Coast	730	743	754	764	775	783	791	799	807	816	824
Los Padres	521	530	538	547	557	566	575	585	594	603	612
Total	19,835	20,100	20,366	20,658	20,945	21,229	21,507	21,788	22,069	22,343	22,617

4.5.2.2 Study results and discussions

Study results in the North Coast and North Bay area are shown in Tables 4-10 and 4-11.

Table 4-10: Worst line/equipment overload summaries for North Coast and North Bay areas

Overloaded Facility	Rating (Amps)	Critical Contingenc(ies)	Category	Loading (%) 2013	2018	CAISO Proposed Solutions
Bridgeville - Garberville 60kV #1 (Bridgeville - Fruitland Jct)	371	T-1 CORTINA 230/115 Bank #4	B	105	112	Second Cortina 230/115 kV Bank or increase import capability to North Geysers
		L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	120	Diverge	
Bridgeville - Garberville 60kV #1 (Fruitland Jct - Ft. Seward)	340	T-1 CORTINA 230/115 Bank #4	B	107	114	
		L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	124	Diverge	
Bridgeville - Garberville 60kV #1 (Ft. Seward - Garberville)	340	T-1 CORTINA 230/115 Bank #4	B	106	113	
		L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	122	Diverge	
Willits - Garberville 60kV #1 (Kekawaka - Laytonville)	337	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	101		
Geysers 3 - Cloverdale 115kV #1	743	L-1 Cortina-Mendocino 115kV and L-1 Redbud-Eagle Rock 115kV	C	113	124	Load dropping
Fulton - Santa Rosa 115kV #1 (Fulton - Monroe 1)	1125	L-1 Fulton-Santa Rosa #2 115kV and L-1 Lakeville-Corona 115kV	C	126	129	Load dropping scheme
Fulton - Santa Rosa 115kV #2 (Fulton - Monroe 2)	1125	L-1 Fulton-Santa Rosa #1 115kV and L-1 Lakeville-Corona 115kV	C	126	129	
Eagle Rock - Cortina 115kV #1 (Cache Jct - Cortina)	668	L-1 Cortina-Mendocino 115kV and G-1 GEYSER #11	B	100	109	Reconductor this section or connect the 115 kV system with 60 kV system
		L-1 Eagle Rock-Geysers#7&8 and L-1 Cortina-Mendocino 115kV	C	102	110	
Eagle Rock - Cortina 115kV #1 (Eagle Rock - Homestake - Highland Jct)	602	L-1 Eagle Rock-Geysers#7&8 and L-1 Cortina-Mendocino 115kV	C	95	103	Load dropping scheme
Sonoma - Pueblo 115kV #1 (Fulton - Pueblo)	743	L-1 Lakeville-Sonoma #1 115kV and L-1 Lakeville-Sonoma #2 115kV	C	109	116	
	602	L-1 Lakeville-Sonoma #1 115kV and L-1 Lakeville-Sonoma #2 115kV	C	135	143	
Fulton - Calistoga 60kV #1 (Fulton - St. Helena)	422	L-1 Lakeville - Dunbar 60kV #1	B	123	135	Reconductor the overloaded section
Fulton 230/115 kV Bank #4	463 MVA	L-1 Lakeville-Corona 115 kV and T-1 Fulton 230/115 kV Bank #9	C	100	110	Load dropping scheme

Table 4-10: Worst line/equipment overload summaries for North Coast and North Bay areas (cont.)

Overloaded Facility	Rating (Amps)	Critical Contingenc(ies)	Category	Loading (%) 2013	Loading (%) 2018	CAISO Proposed Solutions
Eagle Rock - Redbud 115kV #1	512	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	158	Diverge	Second Cortina 230/115 kV Bank or increase import capability to North Geysers
Eagle Rock - Redbud 115kV #1 (Lower Lake Jct - Eagle Rock)	743	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	109		
Eagle Rock 115/60kV Bank #1	80 MVA	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	106		
Fulton - Hopland 60kV #1	327	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	113		
Hopland 115/60kV Bank #2	48 MVA	T-1 EAGLE ROCK 115/60 Bank #1	B	101		1) Second Eagle Rock Bank or 2) A new line between Geyser 17 and Middletown or 3) Connecting 115 kV system from Cortina with 60 kV system
		L-1 Vaca-Tulucay 230kV and T-1 EAGLE ROCK 115/60 Bank #1	C	118		
Mendocino - Clear Lake 60kV #1 (Mendocino - Upper Lake - Hartley)	338	T-1 EAGLE ROCK 115/60 Bank #1	B	110		
		L-1 Elk-Gualala 60kV and T-1 EAGLE ROCK 115/60 Bank #1	C	144		
Clear lake - Eagle Rock 60kV #1 (Clear lake - Konocti)	380	T-1 EAGLE ROCK 115/60 Bank #1	B	128		
		L-1 Elk-Gualala 60kV and T-1 EAGLE ROCK 115/60 Bank #1	C	197		
Clear lake - Eagle Rock 60kV #1 (Lower Lake - Konocti)	344	L-1 Elk-Gualala 60kV and T-1 EAGLE ROCK 115/60 Bank #1	C	142		
Clear lake - Eagle Rock 60kV #1 (Konocti - Eagle Rock)	610	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	124		Second Cortina 230/115 kV Bank
		T-1 EAGLE ROCK 115/60 Bank #1	B	143		Option 1), 2) or 3) above
Clear lake - Hopland 60kV #1 (Clear Lake - Granite)	346	T-1 EAGLE ROCK 115/60 Bank #1	B	143		
Clear lake - Hopland 60kV #1 (Granite - Hopland Jct)	346	T-1 EAGLE ROCK 115/60 Bank #1	B	155		
Ignacio - Mare Island 115kV #2 (Highway Jct - Ignacio)	407	L-1 Ignacio - Carquinez 115kV #1	B	118	128	Reconductor the overloaded sections or long-term plan for this area is needed
	407	L-1 Ignacio - Carquinez 115kV #1 and T-1 Ignacio 230/115 Bank #6	C	121	131	
Ignacio - Mare Island 115kV #1 (Ignacio - Skagg Jct)	407	L-1 Ignacio - Highway 115kV #1	B	103	114	
	407	L-1 Ignacio - Highway 115kV #1 and T-1 Ignacio 230/115 Bank #6	C	104	116	

Table 4-10: Worst line/equipment overload summaries for North Coast and North Bay areas (cont.)

Overloaded Facility	Rating (A)	Critical Contingenc(ies)	Category	Loading (%) 2013	Loading (%) 2018	CAISO Proposed Solutions
Ignacio - Alto - Sausalito 60kV #1 (Ignacio - Hamilton Field Tap)	600	L-1 Greenbrae - Ignacio Jct 60kV #1 and L-1 Ignacio A - Sausalito 60kV #1	C	144	152	Eliminate the switching scheme and use Load dropping
Ignacio - Alto - Sausalito 60kV #2 (Ignacio - Hamilton Field Tap)	600	L-1 Greenbrae - Ignacio Jct 60kV #1 and L-1 Ignacio A - Alto 60kV #1	C	144	152	
Ignacio - Alto 60kV #1 (Ignacio Jct - San Rafael Jct - Greenbrae)	558	L-1 Ignacio A - Alto 60kV #1 and L-1 Ignacio A - Sausalito 60kV #1	C	125	131	Load dropping scheme
	558	L-1 Ignacio A - Alto 60kV #1 and L-1 Ignacio A - Sausalito 60kV #1	C	125	131	
Vaca Dixon - Lakeville 230kV #1	1051	L-1 Lakeville-Geysers #9 230kV and L-1 Vaca-Tulucay 230kV	C	107	104	
Tulucay - Vaca Dixon 230kV #1	1129	L-1 Lakeville-Geysers #9 230kV and L-1 Vaca-Lakeville 230kV	C	105	102	
Lakeville 230/60kV Bank #3	96	L-1 Fulton-Molino-Cotati 60kV and T-1 LAKEVILLE 230/60 Bank #4	C	100	109	
Fulton - Lakeville 230 kV #1	976	L-1 Fulton-Geysers 12 230 kV and T-2 Cotina 230/115 kV Bank #4	C	92	100	
Lakeville 60kV #2	400	L-1 Lakeville-Petaluma C 60kV	B	114	124	Reconductor the overloaded section
	400	L-1 Fulton-Molino-Cotati 60kV and L-1 Lakeville-Petaluma C 60kV	C	154	167	
	481	L-1 Fulton-Molino-Cotati 60kV and L-1 Lakeville-Petaluma C 60kV	C	122	132	
	512	L-1 Fulton-Molino-Cotati 60kV and L-1 Lakeville-Petaluma C 60kV	C	121	130	

Table 4-11: Low voltages summary for North Coast and North Bay areas

Substation	Critical Contingency(ies)	Category	Min Post- 2013	Min Post- 2018	CAISO Proposed Solutions
Fruitland, Fort Seward 60 kV	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.80	0.79	Already addressed in Humboldt mitigation
	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.75	0.74	
Garberville, Kekawaka 60 kV	T-1 Cortina 230/115 Transformer #4	B	0.90	0.89	
	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.65	0.64	
Laytonville, Covelo, Fort Bragg, Big River, Elk, Point Arena, Garcia, Philo 60 kV, Mendocino 115 kV	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.80	0.79	Already addressed in Humboldt mitigation
Sonoma 115 kV	L-1 Lakeville-Sonoma #1 115 kV and L-1 Lakeville-Sonoma #2 115 kV .	C	0.86	0.85	The mitigation plan for thermal problem can be used
Upper Lake 60 kV, Cortina 115 kV, City of Ukiah 115 kV	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.90	0.89	
Hartley, Granite 60 kV	T-1 Eagle Rock 115/60 Transformer #1	B	0.92	0.91	
	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.90	0.89	
Clear Lake 60 kV	T-1 Eagle Rock 115/60 Transformer #1	B	0.87	0.86	
	L-1 Vaca-Tulucay 230 kV and T-1 Eagle Rock 115/60 Transformer #1	C	0.75	0.74	
Konocti, Lower Lake, Middle Town, Eagle Rock 60 kV	T-1 Eagle Rock 115/60 Transformer #1	B	0.67	0.66	
	L-1 Elk-Gualala 60 kV and T-1 Eagle Rock 115/60 Transformer #1	C	0.40	0.39	
Pueblo 115 kV	L-1 Lakeville-Sonoma #1 115 kV and L-1 Lakeville-Sonoma #2 115 kV	C	0.89	0.88	The mitigation plan for thermal problem can be used
Dunbar, St Helena, Calistoga 60 kV	L-1 Lakeville -Dunbar #1 60 kV	B	0.86	0.90	The mitigation plan for thermal problem can be used or eliminate switiching scheme
Greenbrae, Alto, Sausalito 60 kV	L-1 Greenbrae - Ignacio Jct 60 kV #1 and L-1 Ignacio A - Alto 60 kV #1	C	0.83	0.82	The mitigation plan for thermal problem can be used
	L-1 Greenbrae - Ignacio Jct 60 kV #1 and L-1 Ignacio A - Sausalito 60 kV #1	C	0.83	0.82	

4.5.2.3 Recommended solutions for reliability criteria violations

TPL 001-System Performance under Normal Conditions

There is no overload or voltage violation under Category A system performance requirements.

TPL 002-System Performance Following Loss of a single BES Element

Bridgeville-Garberville 60 kV line#1 (Bridgeville-Fruitland Jct.-Ft. Seward-Garberville) Overload

This overload was identified starting in the 2013 summer peak conditions due to power flow to the north Geysers area from the Humboldt area following the outages of Cortina 230/115 kV Bank #4 and its combination. The proposed solutions are:

- Install a second Cortina 230/115 kV transformer
- Improve import capability to the North Geysers area by reinforcing interconnection between the north and south Geysers.

Hopland 115/60 kV Transformer #2 Overload

This transformer can be overloaded following the outage of Eagle Rock 115/60 kV Transformer due to transferred power to serve the North Geysers area. The proposed mitigation plan for this overload is to increase the import capability to the north Geysers area. These may include:

- Installing a second Eagle Rock 115/60 kV Transformer,
- Connecting Geysers 17 with the Middletown substation,
- Connecting the Cortina 115 kV system from the Cortina substation with the local 60 kV system in the North Geysers. In addition, an expansion plan to improve the voltage and thermal loading at Middletown substation area is also recommended.

Mendocino-Clear Lake –Eagle Rock 60 kV line Overload

This overload was triggered, mainly by, the outage of the Eagle Rock 115/60 kV transformer. The proposed solutions for the Hopland 115/60 kV transformer #2 will also mitigate this overload.

Clear Lake –Hopland 60 kV line Overload

This overload was triggered, mainly by, the outage of the Eagle Rock 115/60 kV transformer. The proposed solutions for the Hopland 115/60 kV transformer #2 will also mitigate this overload.

Eagle Rock-Cortina 115 kV line #1 Overload

An overlapping G-1/L-1 contingency can cause an overload of this line. The proposed mitigation plan is to re-conductor the overloaded section. In addition, other proposed upgrades for the North Geysers area might mitigate the overload of this facility.

Fulton-Calistoga 60 kV #1 Overload

This facility can also be overloaded following the outages of Lakeville-Dunbar 60 kV #1 that triggers the operation of the switching scheme in the area. The permanent solutions to this problem are to re-conductor the overloaded section. The short-term solution is to disable the automatic switching scheme during high loads such as summer peak. In addition, the upgrade proposed for the Hopland 115/60 kV transformer #2 may also mitigate this problem as well.

Ignacio-Mare Island 115 kV #1 and #2 Overload

This facility can also be overloaded following an outage of the parallel line. The proposed upgrades for these problems are to re-conductor both of these lines. In addition, transferring load from Highway substation to a stronger source will mitigate these overloads as well.

Lakeville 60 kV line #2 Overload

This facility can be overloaded following the outage of the Lakeville-Petaluma 60 kV line #1. The proposed mitigation plan for this overload is to re-conductor the overloaded facility.

Low voltages on Laytonville, Covelo, Fort Bragg, Big River, Elk, Point Arena, Garcia, Philo 60 kV substations

This facility can be overloaded following an outage of the Lakeville-Petaluma 60 kV line #1. The proposed mitigation plan for this overload is to re-conductor the overloaded facility.

Low voltages on Sonoma, Cortina, Pueblo, City of Ukiah 115 kV and Upper lake, Hartley, Granite, Clearlake, Konocti, Lower Lake, Middletown, Dunbar, St Helena, Calistoga, Greenbrae, Alto, Sausalito, and Eagle Rock60 kV substations

Low voltages on these substations can be observed following several category B contingencies. However, the proposed solution for the thermal overloads will also improve voltage profile in this area.

<u>TPL 003-System Performance Following Loss of Two or More BES Elements</u>

Bridgeville-Garberville 60 kV line#1 (Bridgeville-Fruitland Jct.-Ft. Seward-Garberville) Overload

This is the same overload shown under Category B contingency. However, the percentage overload on these facilities is higher due to the outages of multiple transmission facilities. In general, the proposed solutions for the Category B overloads can also be used.

Willits-Garberville 60 kV line# (Kekawaka-Laytonville) Overload

This section of the line can be overloaded under the same Category B contingency that overload the Bridgeville-Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload.

Geysers 3-Cloverdale 115 kV line #1 Overload

This section of the line can be overloaded following the outages of Cortina-Mendocino 115 kV and L-1 Redbud-Eagle Rock 115 kV lines. The proposed solution for this overload is to drop the load post contingency or to improve import capability to the North Geysers area.

Eagle Rock-Redbud 115 kV line #1 Overload

This section of the line can be overloaded under the same category B contingency that overload the Bridgeville-Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload.

Eagle Rock115/60 kV Transformer #1 Overload

This section of the line can be overloaded under the same Category B contingency that overload the Bridgeville-Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload. Increasing import capability to the North Geysers will also mitigate this overload.

Fulton-Hopland 60 kV line #1 Overload

This section of the line can be overloaded under the same category B contingency that overload the Bridgeville-Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload. Increasing import capability to the North Geysers will also mitigate this overload.

Hopland 115/60 kV Transformer #2 Overload

This overload has been identified under category B contingency and the mitigation plans for category B overload also mitigate this overload problem.

Mendocino-Clear Lake-Eagle Rock 60 kV line Overload

This overload has been identified under category B contingency and the mitigation plans for category B overload also mitigate this overload problem.

Fulton-Santa Rosa 115 kV line #1 or #2 Overload

The overlapping outages of the parallel line and the Lakeville-Corona 115 kV line can overload the remaining line that is still in-service. The proposed solution is to install a load dropping scheme.

Fulton 230/115 kV transformer #4 Overload

This overload was identified following the overlapping outages of the parallel transformer and the Lakeville-Corona 115 kV line. The proposed solution is to install load dropping scheme.

Ignacio-Sausalito 60 kV lines #1 and #2 Overload

This facility can also be overloaded following the outages of Greenbrae-Ignacio Jct. and Ignacio-Sausalito 60 kV lines, mainly due to automatic switching scheme. The permanent solution to this problem is to install a load dropping scheme. The short-term solution is to disable the automatic switching scheme during high load such as summer peak.

Ignacio-Alto 60 kV line #1 Overload

This facility can also be overloaded following the outages of Ignacio-Alto and Ignacio-Sausalito 60 kV lines. The proposed solution to this problem is to install a load dropping scheme.

Vaca Dixon-Lakeville and Tulucay-Vaca Dixon 230 kV lines overload

These are parallel facilities which can be overloaded after the outages of the parallel line and the Lakeville-Geysers 9 230 kV lines. The proposed solutions to these problems are to install load dropping scheme or to implement an operating procedure.

Lakeville 230/60 kV Transformer #3 Overload

This facility can be overloaded after the outage of the parallel transformer and the Fulton-Molino-Cotati 60 kV line. The proposed solutions to these problems are to install load dropping scheme or to implement an operating procedure.

Fulton-Lakeville 230 kV line #1 Overload

This facility can be overloaded after the outage of Fulton-Geysers 12 230 kV line and Cortina 230/115 kV transformer #4. The proposed solutions to these problems are to install load dropping scheme or to implement an operating procedure.

Lakeville 60 kV line #2 Overload

This is the same overload identified under Category B contingency overload. Consequently, the same mitigation plan proposed for category B overload can be used for this condition.

Low voltages on Laytonville, Covelo, Fort Bragg, Big River, Elk, Point Arena, Garcia, Philo 60 kV substations

These low voltages can be triggered by the outages of Cortina 230/115 kV transformer and Ukiah-Cloverdale 115 kV line. The proposed solution to install reactive support in the Humboldt area will also improve voltage level at these substations. However, addition reactive support might be needed.

Low voltages on Sonoma, Cortina, Pueblo, City of Ukiah 115 kV and Upper lake, Hartley, Granite, Clearlake, Konocti, Lower Lake, Middletown, Dunbar, St Helena, Calistoga, Greenbrae, Alto, Sausalito, and Eagle Rock60 kV substations

Low voltages at these substations can be observed following several Category C contingencies. However, the proposed solution for the thermal overloads will also improve voltage profile in this area.

4.5.2.4 Key conclusions

Based on the ISO study assessment, the North Coast/Bay area had:

- No overloads under normal conditions;
- 11 overloads caused by five critical single contingencies[17] under summer peak conditions; and
- 25 overloads caused by 12 critical multiple contingencies under summer peak conditions.[18]

In order to address the identified overloads, the ISO proposed a total of 11 transmission solutions. ISO received seven project proposals through the request window:

- Three were approved;
- Three were withdrawn; and
- One is being evaluated by the ISO and will move forward into the 2010 planning process for further analysis

The ISO approved three projects received through the Request Window and they will carry forward into the 2010 planning process and included in the planning assumptions. The remaining ISO proposals will be carried forward into the 2010 Transmission Plan.

[17] The ISO studies assumed that UVLS in the area shall be used as the safety net and did not model these UVLS in the study

[18] Similar to the single contingency study, UVLS in the area were not included in the study

7.2 Projects Approved by ISO Management

In this section, Table 7-3 lists new projects that received ISO management approval as part of the 2009 transmission planning cycle.

Table 7-3: New transmission projects approved by the ISO Management

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	ISO Justification
1	Humboldt 115/60 kV Transformer Replacements: This is a project proposal to replace Humboldt 115/60 kV Banks #1 and #2 banks with higher ratings transformers (200/220 MVA)	PG&E	Humboldt	Overloads of Humboldt 115/60kV Banks #1 and #2 under various B and C contingencies	Dec-10	15	This proposed project is consistent with the ISO identified solutions to mitigate the overloading problems on these transformers under various category B and C contingency conditions. They also provide operation flexibility in the area.
2	Maple Creek Reactive Support: Install approx 10 MVAR of dynamic reactive support (SVC) at this substation	PG&E	Humboldt	Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek, and Hoopa 60 kV	May-11	10	This proposed project is consistent with the ISO identified solutions to mitigate the low voltage problems at these substations. It also provides dynamic reactive support that increases overall reliability of this system.
3	Garberville Reactive Support: Install approx 20 MVAR of dynamic reactive support (SVC) at this substation	PG&E	Humboldt	Bridgeville, Fruitland, Fort Seward, Garberville, Kekawaka, Laytonville, Covelo 60 kV	May-11	10	This proposed project is consistent with the ISO identified solutions to mitigate the low voltage problems on these substations. It also provides dynamic reactive support that increases overall reliability of this system.

Table 7-3: New transmission projects approved by the ISO Management (cont.)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	ISO Justification
4	**Fulton-Fitch Mountain 60 kV Line Reconductor:** The project proposes to Reconductor the limiting 8 Miles section with 715 Al conductor (631/742A)	PG&E	North Coast/Bay	Overload of Fulton-Hopland 60kV #1 following the outage of L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 Cortina 230/115 Bank #4	May-13	5	This proposed project will increase import capability to the North Geysers area by reconductoring the limiting facility between Fulton-Fitch Mountain 60 kV Line.
5	Clear Lake 60 kV System Reinforcement: This is a project proposal to: 1) Build a new 12-mile 115 kV line (297/345 A) tapping Eagle Rock-Cortina line to Middletown substation. 2) Install 100 MVA 115/60 kV Bank at Middletown substation	PG&E	North Coast/Bay	Overloads of 1) Hopland 115/60kV Bank #2 2) Mendocino-Clear Lake 60kV#1 3) Clear lake-Eagle Rock 60kV#1 4) Clear lake-Hopland 60kV #1 5) Low voltages at several 60 and 115 kV substations in the areas under various B and C contingencies	May-12	30	This project has demonstrated it is a prudent solution to the identified problem since it will connect 115 kV systems from Cortina substation with the 60 kV systems at Middletown substation. It will mitigates the overloads, low voltage problems in this are
6	**Lakeville No. 2 60 kV Switch Upgrade:** This is a project proposal to Replace switch 57 to increase rating of this section from 400 to 440/517A	PG&E	North Coast/Bay	Overload of Lakeville 60kV #2	May-10	1	This proposed project is found to be a better alternative to increase import capability of this line since the limiting facility of this line section is the switch.
7	**Glenn #1 60 kV Reconductoring**: This is a proposal to reconductor 5.5 miles of Glenn #1 60 kV line.	PG&E	North Valley	Mitigate Category B and C criteria violations.	May-13	6-8	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the ISO identified reliability criteria violations.

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, for a Permit to Construct the Fulton-Fitch Mountain Reconductoring Project (U 39 E)	Application No.

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR A PERMIT TO CONSTRUCT THE FULTON-FITCH MOUNTAIN RECONDUCTORING PROJECT

Exhibit F

PG&E's Financial Statement from the Latest Form 10-Q Quarterly Report

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2015**	**2014**	**2015**	**2014**
Operating Revenues				
Electric	$ 3,868	$ 4,012	$ 10,344	$ 10,244
Natural gas	682	927	2,322	2,536
Total operating revenues	**4,550**	**4,939**	**12,666**	**12,780**
Operating Expenses				
Cost of electricity	1,681	1,782	3,958	4,341
Cost of natural gas	50	134	442	694
Operating and maintenance	1,622	1,293	5,028	3,911
Depreciation, amortization, and decommissioning	653	671	1,935	1,765
Total operating expenses	**4,006**	**3,880**	**11,363**	**10,711**
Operating Income	**544**	**1,059**	**1,303**	**2,069**
Interest income	2	1	6	6
Interest expense	(191)	(171)	(567)	(535)
Other income, net	22	19	68	56
Income Before Income Taxes	**377**	**908**	**810**	**1,596**
Income tax provision	72	115	95	325
Net Income	**305**	**793**	**715**	**1,271**
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	**$ 302**	**$ 790**	**$ 705**	**$ 1,261**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited) Balance At September 30, 2015	(Unaudited) Balance At December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$ 62	$ 55
Restricted cash	287	298
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $57 and at respective dates)	1,194	960
Accrued unbilled revenue	907	776
Regulatory balancing accounts	1,857	2,266
Other	300	375
Regulatory assets	475	444
Inventories:		
Gas stored underground and fuel oil	149	172
Materials and supplies	322	304
Income taxes receivable	154	168
Other	327	409
Total current assets	**6,034**	**6,227**
Property, Plant, and Equipment		
Electric	47,141	45,162
Gas	16,419	15,678
Construction work in progress	2,259	2,220
Total property, plant, and equipment	**65,819**	**63,060**
Accumulated depreciation	(20,173)	(19,120)
Net property, plant, and equipment	**45,646**	**43,940**
Other Noncurrent Assets		
Regulatory assets	6,584	6,322
Nuclear decommissioning trusts	2,417	2,421
Income taxes receivable	97	91
Other	1,006	864
Total other noncurrent assets	**10,104**	**9,698**
TOTAL ASSETS	**$ 61,784**	**$ 59,865**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions, except share amounts)	September 30, 2015	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 881	$ 633
Accounts payable:		
Trade creditors	1,286	1,243
Regulatory balancing accounts	803	1,090
Other	455	444
Disputed claims and customer refunds	452	434
Interest payable	139	195
Other	1,932	1,604
Total current liabilities	**5,948**	**5,643**
Noncurrent Liabilities		
Long-term debt	15,195	14,700
Regulatory liabilities	6,294	6,290
Pension and other postretirement benefits	2,435	2,477
Asset retirement obligations	3,620	3,575
Deferred income taxes	9,018	8,773
Other	2,264	2,178
Total noncurrent liabilities	**38,826**	**37,993**
Commitments and Contingencies (Note 9)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	7,127	6,514
Reinvested earnings	8,298	8,130
Accumulated other comprehensive income	5	5
Total shareholders' equity	**17,010**	**16,229**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 61,784**	**$ 59,865**

See accompanying Notes to the Condensed Consolidated Financial Statements.