BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY (U39E) for a Permit to Construct the Ravenswood-Cooley Landing 115 kV Reconductoring Project.	Application No. 17-12-____

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39E) FOR A PERMIT TO CONSTRUCT THE RAVENSWOOD-COOLEY LANDING 115 KV RECONDUCTORING PROJECT

Proponent's Environmental Assessment (Exhibit B) Is Electronically Filed and Excluded from Served Version Due to File Size

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Dated: December 15, 2017

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I. INTRODUCTION AND JUSTIFICATION FOR APPLICATION

Pursuant to Section IX(B) of General Order 131-D ("GO 131-D") of the California Public Utilities Commission ("Commission"), and Rules 2.1 through 2.5 and 3.1 of the Commission's Rules of Practice and Procedure ("Rules"), Pacific Gas and Electric Gas Company ("PG&E") respectfully requests a Permit to Construct ("PTC") the Ravenswood-Cooley Landing 115 kV Reconductoring Project ("Project"). The Project is to replace approximately 1.6 miles of the existing conductors on a portion of the Southeastern Peninsula area 115 kilovolt ("kV") transmission system with new conductors and related modifications to existing steel lattice towers and existing substation equipment.

II. PROJECT OVERVIEW AND PROJECT OBJECTIVES

A. Project Overview

PG&E proposes to reinforce a portion of the Southeastern Peninsula area 115 kV transmission system that provides electrical service to San Mateo and Santa Clara counties by replacing the conductors (a process referred to as "reconductoring") on the approximately 1.6-mile Ravenswood-Cooley Landing 115 kV power line ("Ravenswood-Cooley Landing Line"). The Ravenswood-Cooley Landing Line is a double-circuit tower line design supported by nine lattice steel towers between PG&E's Ravenswood Substation in Menlo Park and Cooley Landing Substation in East Palo Alto on the southeastern portion of the San Francisco Peninsula.

The Southeastern Peninsula area includes the cities of Belmont, San Carlos, Redwood City, Atherton, Menlo Park, East Palo Alto and Palo Alto. PG&E's 60 kV and 115 kV transmission systems in the Southeastern Peninsula Area provide power to six PG&E distribution substations (Belmont, San Carlos, Redwood City, Belle Haven, Glenwood and Menlo) that serve over 98,000 customers, to several customer-owned substations and also to the City of Palo Alto's municipal utility. Under the California Independent System Operator's ("CAISO") Planning Standards, the Southeastern Peninsula area is considered part of a "high urban density area" and therefore requires a high level reliability for the electrical transmission system serving the area.[1]

Power system studies conducted in 2017 by both the CAISO and PG&E have identified the need to improve and upgrade the Ravenswood-Cooley Landing Line to increase capacity in the Southeastern Peninsula area to address potential overloads and future load growth. The studies show that if an outage of two elements of the Southeastern Peninsula area 115 kV system were to occur,[2] both of the Ravenswood-Cooley Landing Line circuits could overload and result in system-wide outages. In this situation, increasing the capacity of the Ravenswood-Cooley Landing Line is necessary to meet CAISO's Planning Standards.[3]

The Project will replace the existing conductors on each of the two Ravenswood-Cooley Landing Line circuits with conductors that have a higher capacity rating. The new conductors will increase the capacity of the Ravenswood-Cooley Landing Line by more than 24 percent. This increased capacity will mitigate potential overloads on the line that could result from

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[1] *See* California ISO Planning Standards § VI (Nov. 2, 2017), which is attached as Exhibit D.

[2] An outage of two elements of an electric transmission system is referred to in the North American Electric Reliability Corporation ("NERC") TPL-001-4 standard as a "P6" contingency.

[3] Section II.6.1 of the California ISO Planning Standards states, "For local area long-term planning, the CAISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate North American Electric Reliability Corporation (NERC) TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems."

outages of other elements on the transmission system in the Southeastern Peninsula area. As a result, the Project will increase electrical capacity to the cities of Belmont, San Carlos, Redwood City, Atherton, Menlo Park and East Palo Alto, which will address the existing potential overload issues and will also accommodate future area load growth.

The Project is on CAISO's list of approved projects in its 2016-2017 Transmission Plan.[4] CAISO reassessed the Project in its 2017-2018 Transmission Planning Process ("TPP"). CAISO staff recommended that the Project should proceed at CAISO's 2017-2018 TPP stakeholder meeting held on November 16, 2017.[5] No adverse comments on CAISO staff's recommendation that the Project should proceed were received from stakeholders by the end of the comment period, which closed on November 30, 2017. Accordingly, PG&E expects that CAISO will continue to designate the Project as "approved" when it issues its final 2017-2018 Transmission Plan.[6]

B. Project Objectives

The Project addresses the need to improve and upgrade the Ravenswood-Cooley Landing Line to increase capacity in the Southeastern Peninsula Area to address potential overloads and future load growth. Specifically, the objectives of the Project are to:

(1) Increase the capacity of the Ravenswood-Cooley Landing Line to address existing overload issues and accommodate future area load growth;

(2) Provide the Southeastern Peninsula area transmission system within San Mateo and Santa Clara counties with greater operational flexibility; and

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4 *See* California ISO 2016-2017 Transmission Plan, Table 7.1, p. 371, relevant excerpts of which are attached as Exhibit E.

5 *See* California ISO, "2017-2018 TPP Projects Recommendations – PG&E Area," Staff Presentation at 2017-2018 Transmission Planning Process Stakeholder Meeting (Nov. 16, 2017), which is attached as Exhibit F.

6 PG&E will provide confirmation to the Commission once CAISO publishes the 2017-2018 Transmission Plan, which is expected in March 2018.

(3) Design and build the project in a safe, cost-effective manner that will also minimize environmental impacts.

III. REGIONAL CONTEXT

The Southeastern Peninsula area's electrical power grid consists of both 60 kV and 115 kV lines that provide power to six distribution substations: Belmont, San Carlos, Redwood City, Belle Haven, Glenwood and Menlo. These substations serve over 98,000 distribution customers in the cities of Belmont, San Carlos, Redwood City, Atherton, Menlo Park and East Palo Alto. In addition, several large customers are supplied with power directly from the local transmission system, including CEMEX, Oracle, Stanford Research Institute, Northrop Grumman, and Facebook. The 115 kV system also delivers power to the municipal utility for the City of Palo Alto and the 60 kV system serves as a back-up source of power to other substations, such as Stanford University and PG&E's Los Altos and Loyola distribution substations.

IV. PROJECT COMPONENTS

The Project involves transmission construction activities consisting of three major elements: (1) reconductoring the existing Ravenswood-Cooley Landing Line; (2) modification of existing steel lattice towers to support the new conductors and a new optical fiber ground wire ("OPGW"); and (3) improving the foundations on four existing steel lattice towers. In addition, temporary structures will be installed and minor modifications will be made to Ravenswood and Cooley Landing substations.

A. Reconductoring the Existing Ravenswood-Cooley Landing Line

PG&E will reconductor the existing Ravenswood-Cooley Landing Line, which consists of a double-circuit 115 kV power line that is approximately 1.6 miles long and runs from Cooley Substation to Ravenswood Substation on nine lattice steel towers. The existing Ravenswood-Cooley Landing Line, which is composed of 715.5 kcmil all-aluminum conductors rated to handle 703 amperes ("amps"), will be reconductored with new 477 kcmil steel-supported aluminum conductors rated to handle 1,144 amps. The 115 kV conductors are arranged in a vertical configuration, with three conductors on each side of the tower. The new conductors will be replaced in the same configuration as the existing 115 kV conductors. Insulators will be replaced along the entire line. The span distances between structures vary from approximately 680 feet to 1,200 feet. In addition, PG&E will install a new OPGW between Ravenswood and Cooley Landing substations for electrical relay communications and lightning protection.

B. Tower Modifications

Tower modifications will consist of installing OPGW peaks to support the new OPGW, cage-top extensions to increase conductor clearance over open water, and structural body modifications to support the additional load from the new conductor. The OPGW peaks, which are typically 4.5-feet lattice extensions mounted to the top of the tower, will be installed on all nine lattice steel towers. Cage-top extensions, which are 10-foot lattice extensions with cross arms bolted to the top of the tower, will be installed on two of the nine lattice steel towers. Tower body modifications, which entail changing out and adding braces to the lower cage portion of the tower, will be made on four of the nine lattice steel towers.

C. Tower Foundation improvements

In order to support the new conductors, the foundations of four of the nine lattice steel towers will be reinforced. This will be done by installing grout-injected soil displacement piles (called Tubex piles) adjacent to the existing tower foundations and structurally tying them to the existing tower footings.

D. Related Work

In addition to the major components described above, temporary structures will be installed during construction. Temporary guard structures consisting of wood poles with guy wires and netting will be installed over road crossings, recreation trails and existing overhead utilities before pulling in the new cable and will be removed after the cable is permanently attached to the nine towers. In addition, temporary wood poles with guy wires will be installed in construction work areas to temporarily anchor the replaced cable until it can be permanently attached to the nine towers with new insulators.

Minor modifications to Cooley Landing and Ravenswood substations will also be made to support the reconductoring of the Ravenswood-Cooley Landing Line and the installation of the new OPGW line. The OPGW line will tie into an existing control building at both substations. At Cooley Landing substation, existing circuit breaker ("CB") 122 will be reconfigured and line relays between the communication building and CB 122 will be replaced within existing conduit.

V. APPLICANT PG&E

This Section describes PG&E and provides information for PG&E that is required under Rules 2.1, 2.2, 2.3, and 3.1.

A. Legal Name and Principal Place of Business (Rule 2.1(a))

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

B. Organization and Qualification to Transact Business (Rule 2.2)

A certified copy of PG&E's Restated Articles of Incorporation, effective April 12, 2004, is on record before the Commission in connection with PG&E's Application 04-05-005, filed with the Commission on May 3, 2004. These articles are incorporated herein by reference pursuant to Rule 2.2 of the Commission's Rules.

C. Financial Statement (Rule 2.3) and Proxy Statement (Rule 3.1(i))

PG&E's most recent Proxy Statement dated April 18, 2017 was filed with the Commission on June 1, 2017 in A.17-06-005, and is incorporated herein by reference. PG&E's balance sheet and an income statement for the three months ending September 30, 2017 was filed with the Commission on November 17, 2017 in A.17-11-009, and is incorporated herein by reference

VI. ADDITIONAL INFORMATION REQUIRED BY PROCEDURAL RULES AND GO 131-D SECTION IX(B)

In accordance with Rule 2.1(c), the proposed category for this proceeding, the need for hearing, the issues to be considered, and a proposed schedule are included at the end of this application, after the signature page and before the verification. In accordance with Rule 2.4(b), PG&E has submitted a Proponent's Environmental Assessment ("PEA"), which is being electronically filed, as Exhibit B to this application. In accordance with Rule 2.5, a deposit for the fees associated with preparation of an environmental impact report or negative declaration is being provided with this application.

The following information is required by Section IX(B)(1) of GO 131-D. Where the required information is provided in the PEA, the relevant section of the PEA is referenced below.

A. A description of the proposed power line or 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 Project is contained in Chapter 2 of the PEA, attached as Exhibit B. A Preliminary Project Schedule for the Project 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 map showing the location of the Project is attached as Exhibit A. Figure 2.3-1 of the PEA (Exhibit B) shows populated areas, parks and recreation areas within 300 feet of the Ravenswood-Cooley Landing Line. Figure 2.4-1 of the PEA (Exhibit B) shows existing electrical transmission and power lines within 300 feet of the Ravenswood-Cooley Landing Line. There are no scenic areas within 300 feet of the Ravenswood-Cooley Landing Line.

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, attached as 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 the proposed power line route or substation location reviews have been undertaken, including a written agency response to applicant's 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.

Consistent with GO 131-D, Section IX(A)(1)(g), PG&E met with several regulatory agencies during the planning stages of the Project. A summary of this governmental agency coordination is provided below and in Section 1.2 of the PEA, which is attached as Exhibit B. Coordination with these agencies will continue throughout the Project's planning and construction process.

On April 10, 2017, PG&E sent a letter to the Native American Heritage Commission ("NAHC") requesting a search of their Sacred Lands files and a list of groups or individuals who might have knowledge of cultural resources in the project area. The NAHC replied on April 11, 2017 that the Sacred Lands file search was negative, and provided PG&E with a list of groups and individuals to be contacted. On May 5, 2018, PG&E sent letters to the groups and individuals provided by the NAHC, and made follow-up phone calls on June 8, 2017. NAHC and Native American tribe written correspondence is included in Appendix B of the PEA and summarized in Table 3.5-5 of the PEA, which attached as Exhibit B.

On May 22, 2017, PG&E met with the City of San Francisco Water Department, Watershed Resource Manager to provide an overview of the Project.

On October 26, 2017, PG&E met with the Menlo Park City Manager and the Director of the Department of Public Works to provide an overview of the Project. On October 31, 2017, PG&E requested that Menlo Park provide a position statement on the Project, but Menlo Park has not provided a response. If PG&E receives a position statement from Menlo Park, PG&E will submit a copy to the Commission for inclusion in the record of this proceeding.

On October 30, 2017, PG&E met with the City of East Palo Alto City Manager and the Director of the Department of Public Works to provide an overview of the Project. On October 31, 2017, PG&E requested that East Palo Alto provide a position statement on the Project, but East Palo Alto has not provided a response. If PG&E receives a position statement from East Palo Alto, PG&E will submit a copy to the Commission for inclusion in the record of this proceeding.

On November 16, 2017, PG&E met with the Senior Planner for the Mid-peninsula Regional Open Space District to provide an overview of the Project.

On November 20, 2017, PG&E consulted with the Assistant City Manager of the City of Palo Alto to provide an overview of the Project and its relationship to the Baylands Natural Preserve.

On November 21, 2017, PG&E met with the Refuge Manager of the Don Edwards San Francisco Bay National Wildlife Refuge to provide an overview of the Project.

E. A PEA or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and this Commission's Rule of Practice and Procedure 2.4 (formerly Rules 17.1 and 17.3). If a PEA is filed, it may include the data described in Items A through D above.

The PEA is attached as <u>Exhibit B</u>. The PEA is being electronically filed.

VII. MEASURES TO REDUCE EMF EXPOSURE

Section X of GO 131-D requires applications for a PTC to describe measures taken to reduce potential exposure to electric and magnetic fields ("EMF") generated by the proposed facilities. In 1993, the Commission issued Decision 93-11-013, which established EMF policy for California's regulated utilities. In 2006, the Commission updated its EMF policy in Decision 06-01-042. The Commission stated in Decision 06-01-042 that "Low-cost EMF mitigation is not necessary in agricultural and undeveloped land except for permanently occupied residences, schools or hospitals located on these lands."[7]

PG&E's "EMF Design Guidelines for Electrical Facilities," which is based on the aforementioned Commission decisions, exempts projects that are located exclusively adjacent to undeveloped land from the requirement to consider no-cost and low-cost EMF reduction measures.[8] In the case of the Project, the adjacent land use next to the right-of-way for the Ravenswood-Cooley Landing Line is undeveloped land. Accordingly, no EMF reduction measures are proposed for the Project.

VIII. PUBLIC NOTICE

Pursuant to Section XI(A) of GO 131-D, notice of this application will be sent to the planning commission and the legislative body for each county or city in which the proposed facilities will be located, including Menlo Park and East Palo Alto. Notice will also be sent to the California Energy Commission, the State Department of Transportation and its Division of Aeronautics, the Secretary of the Resources Agency, the Department of Fish and Wildlife, the Department of Public Health, the Water Resources Control Board, the Air Resources Board, the San Francisco Regional Water Quality Control Board, the Bay Area Air Quality Management District, the Department of Transportation's District Four Office, the State Lands Commission, the U.S. Fish and Wildlife Service, the U.S. Army Corps of Engineers, all owners of land within 300 feet of the Project (as determined by the most recent local assessor's parcel roll available at the time notice is sent), and any other interested parties having requested such notification. Notice will also be provided by advertisement, not less than once a week, two weeks successively, in a newspaper or newspapers of general circulation in the county in which the

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7 Commission Decision 06-01-042, Finding of Fact no. 18 (Jan. 26, 2006).

8 PG&E "EMF Design Guidelines for Electric Facilities," § 3.4, p. 11 (July 21, 2006).

proposed facilities will be located, the first publication to be not later than ten days after filing of the application; and by posting a notice on-site and off-site where the project would be located.

IX. REQUEST FOR TIMELY ACTION

PG&E requests issuance of the PTC by June 2019. Issuance of the PTC by that date would allow the Project to be completed and placed into service by January 2021.

X. EXHIBITS

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

Exhibit A:	Project Map
Exhibit B:	Proponent's Environmental Assessment (Electronically Filed and Excluded from Served Version of Application Due to File Size)
Exhibit C:	Preliminary Project Schedule
Exhibit D:	California ISO Planning Standards
Exhibit E:	California ISO 2016-2017 Transmission Plan Excerpts
Exhibit F:	California ISO, "2017-2018 TPP Projects Recommendations – PG&E Area," Staff Presentation at 2017-2018 Transmission Planning Process Stakeholder Meeting (Nov. 16, 2017)

XI. CONCLUSION

Applicant PG&E respectfully requests that the Commission issue an order pursuant to GO 131-D, effective immediately, granting PG&E a Permit to Construct the Project. Applicant PG&E respectfully requests that the Commission authorize the Energy Division to approve requests by applicant for minor project modifications that may be necessary during final engineering and construction of the project components 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. PG&E respectfully requests that the Commission grant such other and further relief as the Commission finds just and reasonable.

Respectfully submitted,

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By: *_/s/ Mathew J. Swain_*
Mathew J. Swain

Dated: December 15, 2017

Attorneys for Applicant
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 Commission 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. (*See, e.g.*, D.15-03-020 (Mar. 26, 2015) at 25-26; D.13-10-025 (Oct. 23, 2013) at 4-5; D.12-06-039 (June 27, 2012) at 3-4.) Under Section IX.B(f) of GO 131-D, "an application for a permit to construct need not include either a detailed analysis of purpose and necessity, a detailed estimate of cost and economic analysis, a detailed schedule, or a detailed description of construction methods beyond that required for CEQA compliance." No areas of environmental or other public concern are known. If environmental concerns are raised, those can be addressed in the environmental review process and do not require separate hearings. If other 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.

PG&E 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 are true of my own knowledge, except as to matters which are therein stated no 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 15, 2017, at San Francisco, California.

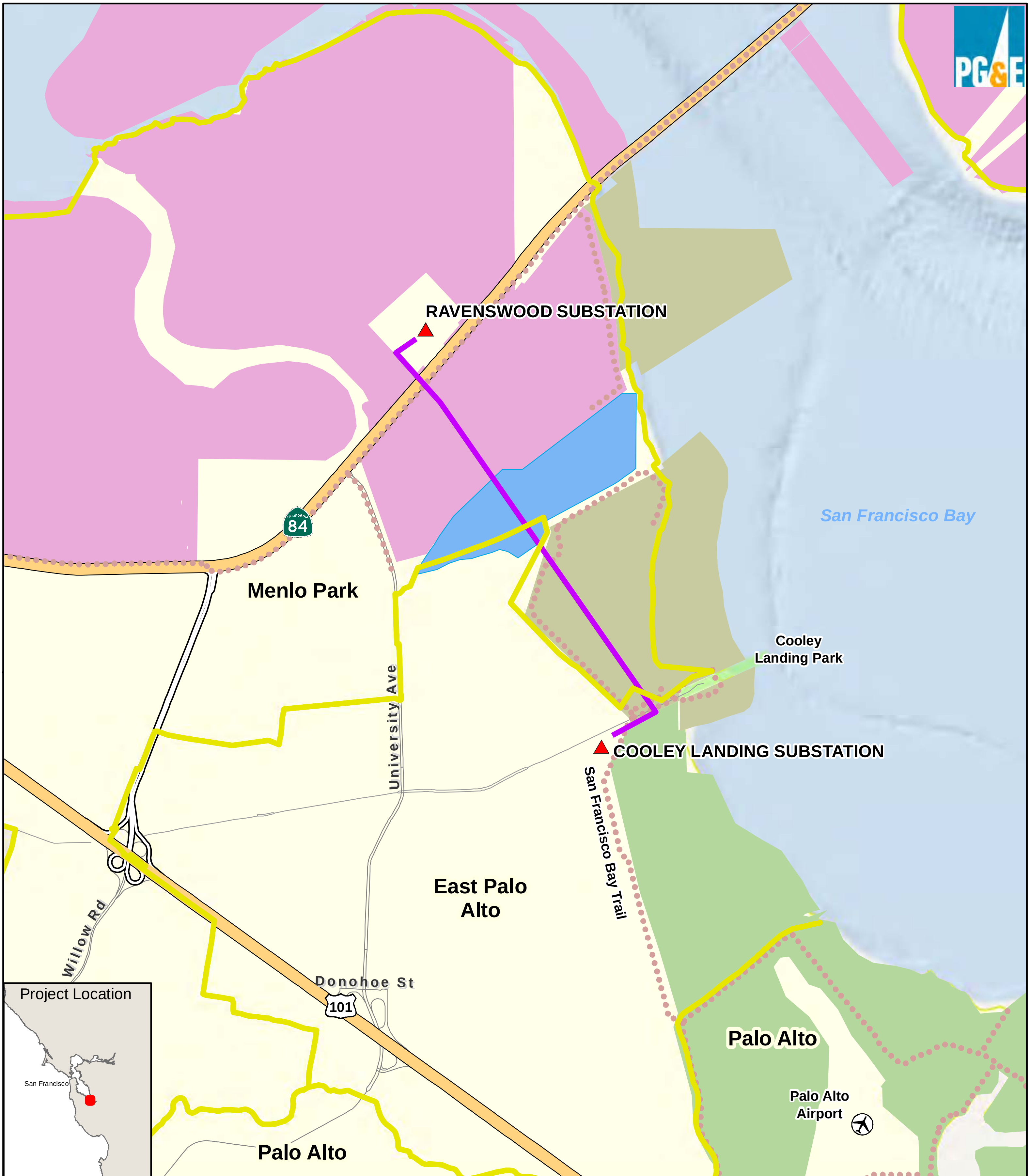
/s/ Andrew Williams

Andrew Williams

Vice President, Safety, Health and Environment

<u>EXHIBIT A</u>

<u>Project Map</u>



- Substation
- Ravenswood-Cooley Landing 115 kV Powerline
- San Francisco Bay Trail
- City Limits
- Don Edwards National Wildlife Refuge
- San Francisco Public Utilities Commission
- Palo Alto Baylands Nature Preserve
- Ravenswood Open Space Preserve

Project Overview Map

Ravenswood-Cooley Landing 115kV Reconductoring Project

0 0.1 0.2 0.3 0.4 Miles

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<u>EXHIBIT B</u>

<u>Proponent's Environmental Assessment</u>

The PEA Was Electronically Filed and Excluded from Served
Version of Application
Due to File Size

EXHIBIT C

Preliminary Project Schedule

Exhibit C

PRELIMINARY PROJECT SCHEDULE

RAVENSWOOD-COOLEY LANDING 115 kV RECONDUCTORING PROJECT

Application for PTC submitted	December 15, 2017
Deficiency notice, if any	January 15, 2018
Protests and responses due	January 25, 2018
Response to any deficiencies	February 14, 2018 or sooner
Replies to any protests or responses	February 5, 2018
Application deemed complete	March 19, 2018
Draft Mitigated Negative Declaration (MND) released	July 19, 2018
Close of Public Review Period	August 20, 2018
Mitigated Negative Declaration (MND) adopted per CEQA requirements (no later than 180 days from complete application per CEQA Guidelines § 15107)	September 17, 2018
Requested date by which MND Adopted and PTC Decision Approved and Effective	June 2019
Acquisition of other required permits	June 2019 – September 2020
Acquisition of land rights as needed	June 2019 – September 2020
Materials Procurement	January 2019 – July 2019
Initial Notice to Proceed / Construction Begins	September 2020
Project Operational	January 2021

EXHIBIT D

California ISO Planning Standards

California ISO
Planning Standards

Effective November 2, 2017

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I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant), and the WECC Regional Criteria:

http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States

https://www.wecc.biz/Standards/Pages/Default.aspx

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control

The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.

2. Voltage Standard

Voltage and system performance must meet WECC Regional Criteria TPL-001-WECC-CRT-3 https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-3.1.pdf.

In accordance with Requirements WR2 and WR3 of WECC Regional Criteria TPL-001-WECC-CRT-3 the following standards and limits are to be used within the ISO controlled grid.

Table 1: ISO steady state voltage standard.

Voltage level	Normal Conditions (P0)		Contingency Conditions (P1-P7)		Voltage Deviation
	Vmax (pu)	Vmin (pu)	Vmax (pu)	Vmin (pu)	P1&P3
≤ 200 kV	1.05	0.95	1.10	0.90	≤8%
≥ 200 kV	1.05	0.95	1.10	0.90	≤8%
≥ 500 kV	1.05	1.00	1.10	0.90	≤8%

The voltage deviation applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load). The maximum total voltage deviation for standard TPL-001-4 category P3 is ≤8% measured from the voltage that exists after the initial condition (loss of generator unit followed by system adjustments) and therefore takes into consideration only voltage deviation due to the second event.

All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO and will be documented through stakeholder process. The ISO will make public all exceptions through its website.

Exceptions and clarifications by PTO area:

Table 2: System Voltage Limits in SCE Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
All buses	525 kV	540/1.029	520/0.990	550/1.048[2]	498.8/0.950
Alamitos, Arcogen, Huntington Beach, Mandalay, Redondo	230 kV	230/1.000[1]	220/0.957	230/1.000[2]	207/0.900
Bailey, Chevmain, Cima, Colorado River, Cool Water, Eagle Mt., Eagle Rock, El Casco, Gene, Harborgen, Highwind, Iron Mt., Inyo, Ivanpah, Johanna, Lewis, Primm, Rancho Vista, Red Bluff, Sandlot, Santiago, Serrano, Whirlwind, Windhub	230 kV	241.5/1.050	218.5/0.95	245/1.065[2]	207/0.900
All other buses	230 kV	241.5/1.050	218.5/0.95	242/1.052[2]	207/0.900
Eagle Mtn, Blythe	161 kV	169/1.050[2]	152.95/0.950	169/1.050[2]	144.9/0.900
Cool Water, Inyokern, Kramer, Victor	115 kV	120.75/1.050	109.25/0.950	121/1.052[2]	103.5/0.900
Control, Inyo	115 kV	120.75/1.05	117/1.026	121/1.052[2]	114.5/0.996
All other buses	115 kV	120.75/1.050	109.25/0.950	123/1.070[2]	103.5/0.900
All buses	66 kV	69.3/1.050	62.7/0.950	72.5/1.090[2]	59.4/0.900

[1] Due to equipment (circuit breaker) voltage limit.

Table 3: System Voltage Limits in PG&E Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
DCPP bus	500 kV	545/1.090	512/1.024	550/1.100	512/1.024
All other buses	500 kV	550/1.100	518/1.036	550/1.100	473/0.946
DCPP bus	230 kV	242/1.052	218/0.948	242/1.052	207/0.900
All other buses	230 kV	242/1.052	219/0.952	242/1.052	207/0.900
All buses	115 kV	121/1.052[2]	109/0.948	121/1.052[1]	104/0.904
All buses	70 kV	72.5/1.036	66.5/0.950	72.5/1.036	63.0/0.900
All buses	60 kV	63.0/1.050	57.0/0.950	66.0/1.100	54.0/0.900

Maximum voltage deviation: DCPP 230 kV bus at 11 kV or 4.78%.

Table 4: System Voltage Limits in SDG&E Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High Limit (kV)	Low Limit (kV)	High Limit (kV)	Low Limit (kV)
All buses	525 kV	550/1.048	498.75/0.950	550/1.048	472.5/0.900
All buses	230 kV	241.5/1.050	218.5/0.950	241.5/1.050	207/0.900
All buses	138 kV	144.9/1.050	131.1/0.950	144.9/1.050	124.2/0.900
All buses	69 kV	72.45/1.050	65.55/0.950	72.45/1.050	62.1/0.900

Table 5: System Voltage Limits in VEA Area

System	Facility	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
All buses	230 kV	248.4/1.080	218.5/0.950	253/1.100	207/0.900
All buses	138 kV	149.0/1.080	131.1/0.950	151.8/1.100	124.2/0.900

Table 6: System Voltage Limits for Trans Bay Cable

System	Facility	Steady State Pre-Contingency		Steady State Post-Contingency	
		High Limit (kV/p.u.)	Low Limit (kV/p.u.)	High Limit (kV/p.u.)	Low Limit (kV/p.u.)
All buses	230 kV	241.5/1.050	218.5/0.950	253/1.100	207/0.900
All buses	115 kV	120.75/1.050	109.25/0.950	126.5/1.100	103.5/0.900

[2] PG&E Utility Standard TD1036S allows 115 kV voltages to operate as high as 126 kV until capital projects can be placed into service to achieve a desired operating limit of 121 kV.

3. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP, and Appendix E of the Transmission Control Agreement located on the ISO web site at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=3972DF1A-2A18-4104-825C-E24350BA838F

4. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL-001-4 standard for single contingencies (P1). Supporting information is located in Section IV of this document. Furthermore any reference to the loss of a "generator unit" in the NERC multiple contingency standards (P3-P5) shall be similar to the loss of a "single module of a combined cycle power plant".

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.
b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.
c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

5. Planning for New Transmission versus Involuntary Load Interruption Standard

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL-001-4 P1) should result in loss of more than 250 MW of load.
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines “closed in” during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

6. Planning for High Density Urban Load Area Standard

6.1 Local Area Planning

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources.[3] The local areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local generation and transmission capacity. Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels.

For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

- In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.
- In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas

[3] A “local area” for purposes of this Planning Standard is not necessarily the same as a Local Capacity Area as defined in the CAISO Tariff.

that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, number of customers impacted by the outage, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

6.2 System Wide Planning

System planning is characterized by much broader geographical size, with greater transmission import capability and most often with plentiful resources that usually can be procured at somewhat lower prices than local area resources. Due to this fact more resources are available and are easier to find, procure and dispatch. Provided it is allowed under NERC reliability standards, the ISO will allow non-consequential load dropping system-wide SPS schemes that include some non-consequential load dropping to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

7. Extreme Event Reliability Standard

The requirements of NERC TPL-001-4 require Extreme Event contingencies to be assessed; however the standard does not require mitigation plans to be developed for these Extreme Events. The ISO has identified in Section 7.1 below that the San Francisco Peninsula area has unique characteristics requiring consideration of corrective action plans to mitigate the risk of extreme events. Other areas of the system may also be considered on a case-by-case basis as a part of the transmission planning assessments.

7.1 San Francisco-Peninsula - Extreme Event Reliability Standard

The ISO has determined through its Extreme Event assessments, conducted as a part of the annual transmission planning process, that there are unique characteristics of the San Francisco Peninsula area requiring consideration for mitigation as follows.

- high density urban load area,
- geographic and system configuration,
- potential risks of outages including seismic, third party action and collocating facilities; and
- challenging restoration times.

The unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages that are beyond the application of mitigation of extreme events in the reliability standards to the rest of the ISO controlled grid. The ISO will consider the overall impact of the mitigation on the identified risk and the associated benefits that the mitigation provides to the San Francisco Peninsula area.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is "an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability." In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards and should be used in the development of any new SPS. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies). This is to emphasize that best engineering practice and judgment will need to be exercised by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of SPS in all potential applications.

ISO SPS1
The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2
The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3
The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the minimum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4
For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the transmission line that the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) Voltage instability, transient instability, or small signal instability: While these are rare concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

ISO SPS5

Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno, etc.) and grid-wide need to be evaluated as a whole and studied as such.

ISO SPS6

The SPS must be simple and manageable. As a general guideline:

A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.

B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:

   i. The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.

   ii. If the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.

C) Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided.

D) An SPS should not require real-time operator actions to arm or disarm the SPS or change its set points.

ISO SPS7

If the SPS is designed for new generation interconnection, the SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO SPS8

Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

ISO SPS9

The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

ISO SPS10

The ISO, in coordination with affected parties, may relax SPS requirements as a temporary "bridge" to system reinforcements. Normally this "bridging" period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

ISO SPS11

The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO SPS12

The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO SPS13

All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation.

ISO SPS14

To ensure that the ISO's transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15

The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17
Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

IV. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL-001-4 standard for single contingencies (P1).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL-001-4 standard P1.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISO's determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)[4]. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

[4] Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages [5]that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover, the ISO considers that the level of facility forced outages is significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter[6]	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos[7]	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta[8]	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

[5] Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.
[6] Data for Sutter is recorded from 07/03/01 to 08/10/02
[7] Data for Los Medanos is recorded from 08/23/01 to 08/10/02
[8] Data for Delta is recorded from 06/17/02 to 08/10/02

V. Background behind Planning for New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under certain contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL-001-4 P1) may result in loss of more than 250 MW of load.

   This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL-001-4 P1) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the radial and/or consequential loss of load allowed under NERC standard TPL-001-4 single contingencies (P1).

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

   This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

   This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

   It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- The maximum amount of load that would need to be interrupted.
- The duration of the interruption.
- The annual energy that would not be served or delivered.
- The number of interruptions per year.
- The time of occurrence of the interruption (e.g., week day summer afternoon).
- The number of customers that would be interrupted.
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural).
- Value of service or performance-based ratemaking assumptions concerning the dollar impact of a load interruption.

The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VI. Background behind Planning for High Density Urban Load Area Standard for Local Areas

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources. These areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local resource and transmission capacity. The need for system reinforcement in a number of local areas is expected to climb due to projected resource retirements, with single and double contingency conditions playing a material role in driving the need for reinforcement. Relying on load shedding on a broad basis to meet these emerging needs would run counter to historical and current practices, resulting in general deterioration of service levels. One of the fundamental ISO Tariff requirements is to maintain service reliability at pre-ISO levels, and it drives the need to codify the circumstances in which load shedding is not an acceptable long-term solution:

1. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

   This standard is intended to continue avoiding the need to drop load in high density urban load areas due to, among other reasons, high impacts to the community from hospitals and elevators to traffic lights and potential crime.

   The following is a link to the 2010 Census Urban Area Reference Maps:

   http://www.census.gov/geo/maps-data/maps/2010ua.html

   This site has diagrams of the following urbanized areas which contain over one million persons.

   Los Angeles--Long Beach--Anaheim, CA
   San Francisco--Oakland, CA
   San Diego, CA
   Riverside--San Bernardino, CA
   San Jose, CA

2. In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.

   This standard is intended to insure that a reliable transition exists between the time when problems could arise until long-term transmission upgrades are placed in service.

3. In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

It is ISO's intention to thoroughly evaluate the risk of outages and their consequences any time a load shedding SPS is proposed regardless of population density.

VII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

Footnote 12 of TPL-001-4 Interpretation and Applicable Timeline[9]: The shedding of Non-Consequential load following P1, P2-1 and P3 contingencies on the Bulk Electric System of the ISO Controlled Grid is not considered appropriate in meeting the performance requirements. In the near-term planning horizon the requirements of Footnote 12 may be applied until the long-term mitigation plans are in-service. In the near-term transmission planning horizon, the non-consequential load loss will be limited to 75 MW and has to meet the conditions specified in Attachment 1 of TPL-001-4.

[9] Implementation and applicable timeline will remain the same as the "Effective Date:"(s) described in the NERC TPL-001-4 standard.

High Density Urban Load Area: Is an Urbanized Area, as defined by the US Census Bureau[10] with a population over one million persons.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. For studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a more stringent standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified and corresponding operating procedures are in place when required.

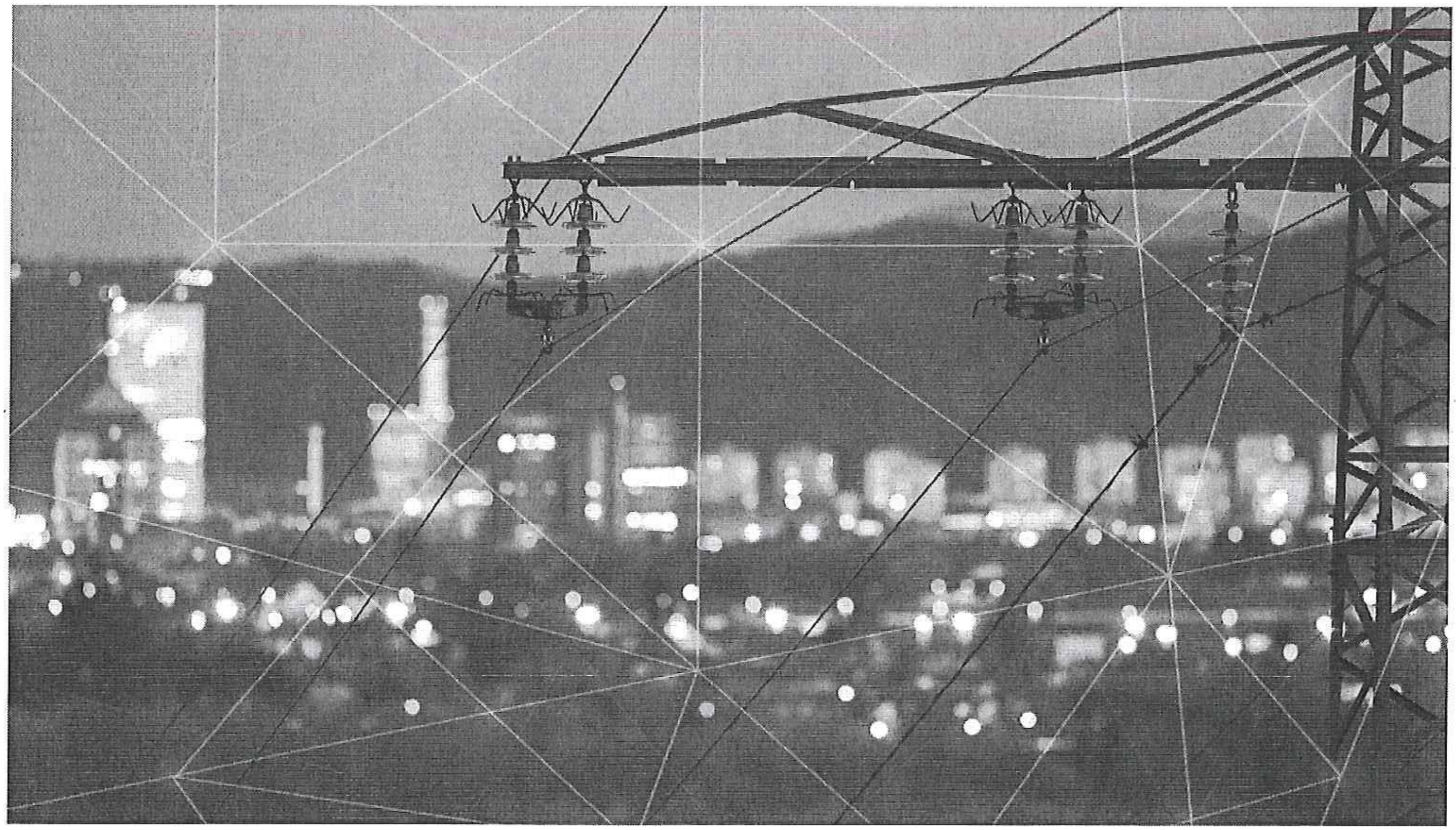
Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

[10] Urbanized Area (UA): A statistical geographic entity consisting of a densely settled core created from census tracts or blocks and contiguous qualifying territory that together have a minimum population of at least 50,000 persons.

EXHIBIT E

California ISO 2016-2017 Transmission Plan Excerpts

2016-2017 TRANSMISSION PLAN



California ISO

March 17, 2017
BOARD APPROVED

Chapter 7

7 Transmission Project List

7.1 Transmission Project Updates

Table 7.1-1 and Table 7.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous transmission plans, the ISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location constrained resource interconnection facility project or enhance economic efficiencies.

Table 7.1-1: Status of Previously Approved Projects Costing Less Than $50M

No	Project	PTO	Expected In-Service Date
1	Trans Bay Cable Dead Bus Energization Project	TransBay Cable	Completed
2	Estrella Substation Project	NEET West	May-19
3	Almaden 60 kV Shunt Capacitor	PG&E	Canceled
4	Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor	PG&E	May-18
5	Borden 230 kV Voltage Support	PG&E	May-19
6	Caruthers – Kingsburg 70 kV Line Reconductor	PG&E	Apr-19
7	Cascade 115/60 kV No.2 Transformer Project and Cascade – Benton 60 kV Line Project	PG&E	May 19 and Nov-22
8	Cayucos 70 kV Shunt Capacitor	PG&E	May-21
9	Christie 115/60 kV Transformer No. 2	PG&E	Jan-2018
10	Clear Lake 60 kV System Reinforcement	PG&E	Feb-23
11	Contra Costa – Moraga 230 kV Line Reconductoring	PG&E	Completed
12	Contra Costa Sub 230 kV Switch Replacement	PG&E	Dec-17
13	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	May-2018

14	Cortina No.3 60 kV Line Reconductoring Project	PG&E	May-2019
15	Cressey – North Merced 115 kV Line Addition	PG&E	Canceled
16	Diablo Canyon Voltage Support Project	PG&E	Jul-19
17	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	Dec-2020
18	Estrella Substation Project	PG&E/NEET West[131]	May-19
19	Evergreen-Mabury Conversion to 115 kV *	PG&E	Jun-21
20	Fulton 230/115 kV Transformer	PG&E	May-22
21	Fulton-Fitch Mountain 60 kV Line Reconductor	PG&E	Aug-18
22	Glenn #1 60 kV Reconductoring	PG&E	Apr-21
23	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	Dec-2018
24	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	Mar-2018
25	Helm-Kerman 70 kV Line Reconductor	PG&E	May-17
26	Ignacio – Alto 60 kV Line Voltage Conversion	PG&E	Mar-23
27	Jefferson-Stanford #2 60 kV Line	PG&E	On hold
28	Kern – Old River 70 kV Line Reconductor Project	PG&E	Dec-16
29	Kern PP 230 kV Area Reinforcement	PG&E	Apr-23
30	Kearney-Caruthers 70 kV Line Reconductor	PG&E	Apr-2019
31	Kearney – Hearndon 230 kV Line Reconductoring	PG&E	Mar-2019

131 NEET West was awarded the 230 kV substation component of the project through competitive solicitation. PG&E will construct and own the 70 kV substation and associated upgrades.

32	Kearney-Kerman 70 kV Line Reconductor	PG&E	Canceled
33	Lemoore 70 kV Disconnect Switches Replacement	PG&E	Apr-2017
34	Lockheed No.1 115 kV Tap Reconductor	PG&E	Canceled
35	Lodi-Eight Mile 230 kV Line	PG&E	Sep-2019
36	Los Banos-Livingston Jct-Canal 70 kV Switch Replacement	PG&E	Jan-2018
37	Los Esteros-Montague 115 kV Substation Equipment Upgrade	PG&E	Mar-21
38	Maple Creek Reactive Support	PG&E	Jan-2020
39	McCall-Reedley #2 115 kV Line	PG&E	May-22
40	Menlo Area 60 kV System Upgrade	PG&E	Completed
41	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	Completed
42	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	May-19
43	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	Apr-22
44	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Nov-2026
45	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	Apr-2019
46	Missouri Flat – Gold Hill 115 kV Line	PG&E	Dec-18
47	Monta Vista – Los Gatos – Evergreen 60 kV Project	PG&E	Canceled
48	Monte Vista 230 kV Bus Upgrade	PG&E	Apr-2020
49	Moraga Transformers Capacity Increase	PG&E	Completed
50	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Mar-21
51	Moraga-Oakland "J" SPS Project	PG&E	Completed
52	Morro Bay 230/115 kV Transformer Addition Project	PG&E	Apr-2019
53	Mosher Transmission Project	PG&E	May2019

54	Mountain View/Whisman-Monta Vista 115 kV Reconductoring	PG&E	Canceled
55	Napa – Tulucay No. 1 60 kV Line Upgrades	PG&E	Jul-20
56	Navidad Substation Interconnection	PG&E	Canceled
57	North Tower 115 kV Looping Project	PG&E	Dec-21
58	NRS-Scott No. 1 115 kV Line Reconductor	PG&E	May-18
59	Oakhurst/Coarsegold UVLS	PG&E	May-17
60	Oro Loma – Mendota 115 kV Conversion Project	PG&E	May-19
61	Oro Loma 70 kV Area Reinforcement	PG&E	Apr-23
62	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	May-20
63	Pease-Marysville #2 60 kV Line	PG&E	Canceled
64	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	May-22
65	Pittsburg-Lakewood SPS Project	PG&E	Completed
66	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	May-21
67	Reedley 70 kV Reinforcement	PG&E	Feb-20
68	Reedley 115/70 kV Transformer Capacity Increase	PG&E	May-21
69	Reedley-Dinuba 70 kV Line Reconductor	PG&E	Mar-19
70	Reedley-Orosi 70 kV Line Reconductor	PG&E	Dec-18
71	Rio Oso – Atlantic 230 kV Line Project	PG&E	Dec-22
72	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Jul-21
73	Rio Oso Area 230 kV Voltage Support	PG&E	Feb-22
74	Ripon 115 kV Line	PG&E	Apr-22
75	San Bernard – Tejon 70 kV Line Reconductor	PG&E	Jan-18

76	San Mateo – Bair 60 kV Line Reconductor	PG&E	May-23
77	Semitropic – Midway 115 kV Line Reconductor	PG&E	Jan-19
78	Series Reactor on Warnerville-Wilson 230 kV Line	PG&E	Dec-17
79	Soledad 115/60 kV Transformer Capacity	PG&E	Canceled
80	South of San Mateo Capacity Increase *	PG&E	Feb-29
81	Spring 230/115 kV substation near Morgan Hill **	PG&E	May-21
82	Stagg – Hammer 60 kV Line	PG&E	Aug-22
83	Stockton 'A' –Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	Jun-19
84	Stone 115 kV Back-tie Reconductor	PG&E	Canceled
85	Table Mountain – Sycamore 115 kV Line	PG&E	Dec-25
86	Taft-Maricopa 70 kV Line Reconductor	PG&E	Canceled
87	Tesla 115 kV Capacity Increase	PG&E	Completed
88	Tesla-Newark 230 kV Path Upgrade	PG&E	Canceled
89	Vaca Dixon – Lakeville 230 kV Reconductoring	PG&E	Canceled
90	Vierra 115 kV Looping Project	PG&E	Feb-23
91	Warnerville-Bellota 230 kV line reconductoring	PG&E	Aug-22
92	Watsonville Voltage Conversion *	PG&E	Jun-21
93	Weber 230/60 kV Transformer Nos. 2 and 2A Replacement	PG&E	Completed
94	Weber-French Camp 60 kV Line Reconfiguration	PG&E	Completed
95	West Point – Valley Springs 60 kV Line	PG&E	May-19
96	Wheeler Ridge Voltage Support	PG&E	Mar-19
97	Wheeler Ridge-Weedpatch 70 kV Line Reconductor *	PG&E	Jan-19

98	Wilson 115 kV Area Reinforcement	PG&E	May-19
99	Wilson-Le Grand 115 kV line reconductoring	PG&E	Dec-20
100	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	Dec-20
101	Bellota 230 kV Substation Shunt Reactor	PG&E	Jan-19
102	Cottonwood 115 kV Substation Shunt Reactor	PG&E	Jan-19
103	Delevan 230 kV Substation Shunt Reactor	PG&E	Feb-19
104	Ignacio 230 kV Reactor	PG&E	Jun-20
105	Los Esteros 230 kV Substation Shunt Reactor	PG&E	May-19
106	Wilson 115 kV SVC	PG&E	Dec-20
107	2nd Escondido-San Marcos 69 kV T/L	SDG&E	Dec-20
108	2nd Pomerado - Poway 69kV Circuit	SDG&E	Jun-18
109	Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously approved New Sycamore - Bernardo 69 kV line)	SDG&E	Feb-19
110	Miguel 500 kV Voltage Support (aka Miguel VAR Support)	SDG&E	Apr-17
111	Miramar-Mesa Rim 69 kV System Reconfiguration	SDG&E	Jun-18
112	Mission Bank #51 and #52 replacement	SDG&E	Jun-18
113	Mission-Penasquitos 230 kV Circuit *	SDG&E	Jun-19
114	Reconductor TL663, Mission-Kearny	SDG&E	Jun-18
114	Reconductor TL676, Mission-Mesa Heights	SDG&E	Jun-18
116	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	Feb-21
117	Rose Canyon-La Jolia 69 kV T/L	SDG&E	Jun-18
118	Sweetwater Reliability Enhancement	SDG&E	Jun-20

119	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	Dec-17
120	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Dec-20
121	TL633 Bernardo-Rancho Carmel Reconductor	SDG&E	Feb-19
122	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Jun-20
123	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	Dec-19
124	TL690A, San Luis Rey-Oceanside Tap	SDG&E	Completed
125	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	Jan-21
126	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	Completed
127	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Dec-19
128	TL 13820, Sycamore-Chicarita Reconductor	SDG&E	Jun-18
129	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	Dec-21
130	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	Dec-17
131	Upgrade Los Coches 138/69 kV bank 51	SDG&E	Completed
132	15 Mvar Capacitor at Basilone Substation	SDG&E	Jun-17
133	30 Mvar Capacitor at Pendleton Substation	SDG&E	Jun-17
134	Reconductor TL 605 Silvergate – Urban	SDG&E	Jun-18
135	Second Miguel – Bay Boulevard 230 kV Transmission Circuit	SDG&E	Jun-19
136	TL600: "Mesa Heights Loop-in + Reconductor	SDG&E	Jun-18
137	Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Swap	SCE	Jun-18
138	Kramer Reactors	SCE	Dec-17
139	Laguna Bell Corridor Upgrade	SCE	Dec-20

140	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-20
141	Method of Service for Wildlife 230/66 kV Substation	SCE	Jun-21
142	Path 42 and Devers – Mirage 230 kV Upgrades	SCE	Dec-16
143	Victor Loop-in	SCE	Jun-17
144	Eagle Mountain Shunt Reactors	SCE	Dec-18
145	CT Upgrade at Mead-Pahrump 230 kV Terminal	VEA	Completed

Notes:

* The project requires further evaluation in future planning cycles to reassess the need scope of the project. All development activities are recommended to be put on hold until a review is completed.

** The project requires further evaluation in future planning cycles to reassess the need scope of the project. The project is in the late stages of design, siting, and permitting, and continuing the design, siting and permitting activities will assist in the review. However, the ISO is recommending that the project sponsors do not proceed with filings for permitting and certificates of public convenience and necessity until the ISO completes the review.

EXHIBIT F

California ISO, "2017-2018 TPP Projects Recommendations – PG&E Area," Staff Presentation at 2017-2018 Transmission Planning Process Stakeholder Meeting (Nov. 16, 2017)

2017-2018 TPP Projects Recommendations – PG&E Area

Binaya Shrestha
Regional Transmission Engineer Lead

2017-2018 Transmission Planning Process Stakeholder Meeting
November 16, 2017

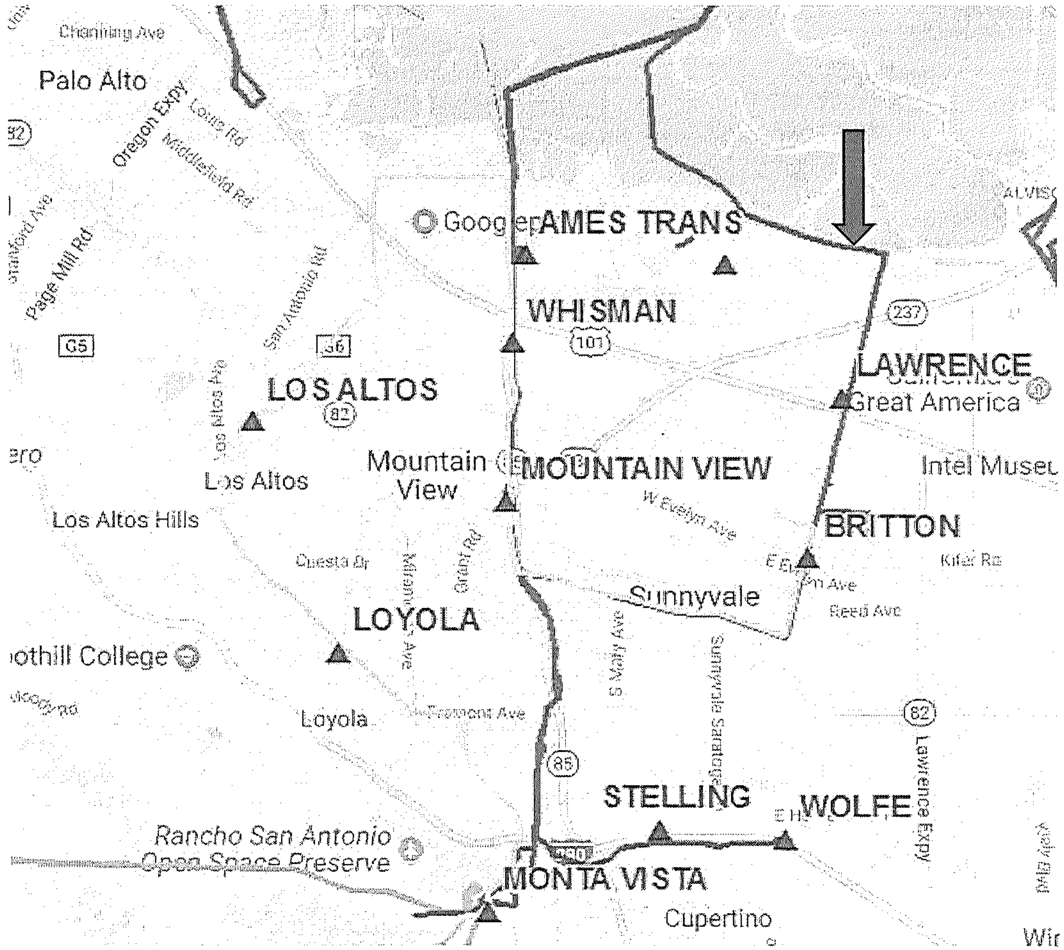
Presentation Outline

- New < $50 million projects concluded at this time for approval recommendation
- Review of previously approved projects
  - Projects modeled in base cases are still required to meet reliability needs
  - Projects not modeled in base cases
    - < $50 million projects concluded at this time to proceed with current scope
    - < $50 million projects concluded at this time to be canceled
    - < $50 million projects concluded at this time to proceed with revised scope
  - > $50 million projects will have assessments included in the draft ISO 2017-2018 Transmission Plan to be posted by January 31, 2018 for stakeholder comment.
  - Review of projects approved in 2012-2013 Transmission Plan in the Central California Study

New Projects Recommended for Approval (Less than $50M projects)

Newark-Lawrence 115 kV Line Upgrade (Greater Bay Area)

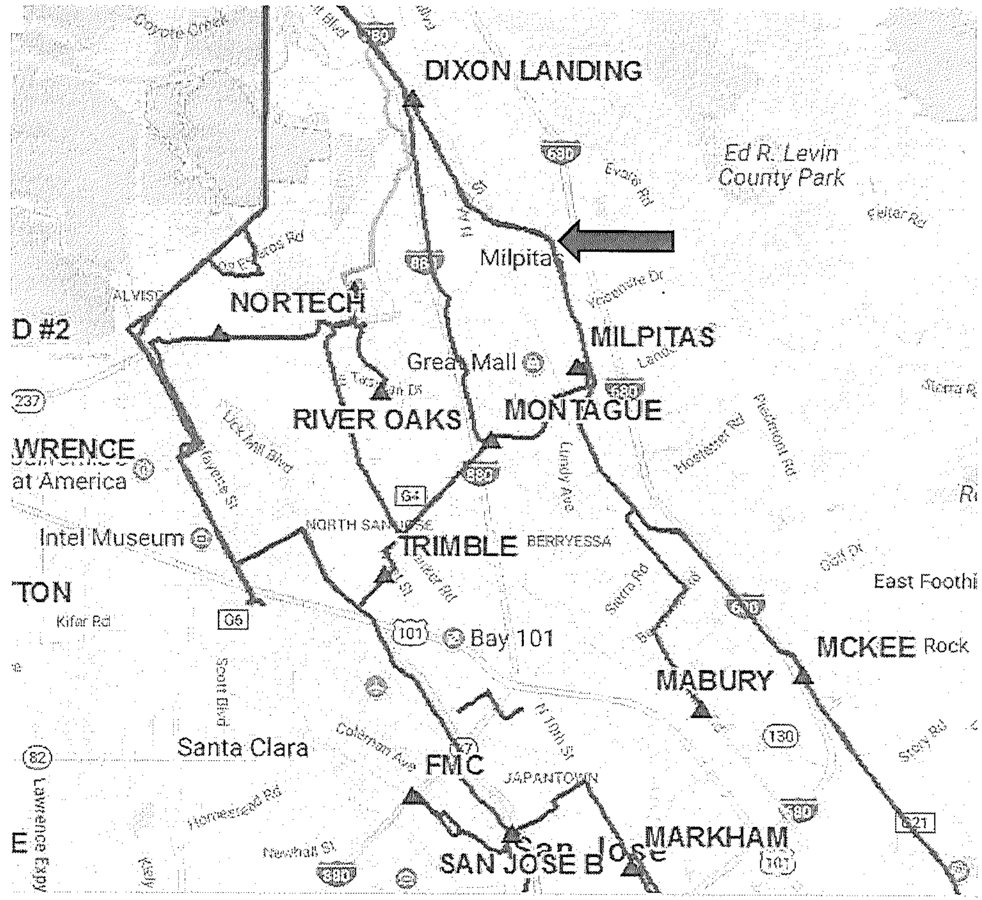
- Reliability Assessment Need
  - NERC Categories P7 starting 2019 and P6 thermal overloads starting 2022.
  - Overloads worsen in peak-shift and high CEC forecast sensitivities.
- Project Submitter
  - ISO
- Project Scope
  - Upgrade limiting equipment
    - circuit breaker at Newark
- Project Cost
  - $1.5M-$2M
- Alternatives Considered
  - Rerate
  - Battery Energy Storage
- Recommendation
  - Approval



Map source: PG&E solar photovoltaic and renewable auction mechanism (PV RAM) project map

Newark-Milpitas #1 115 kV Line Upgrade (Greater Bay Area)

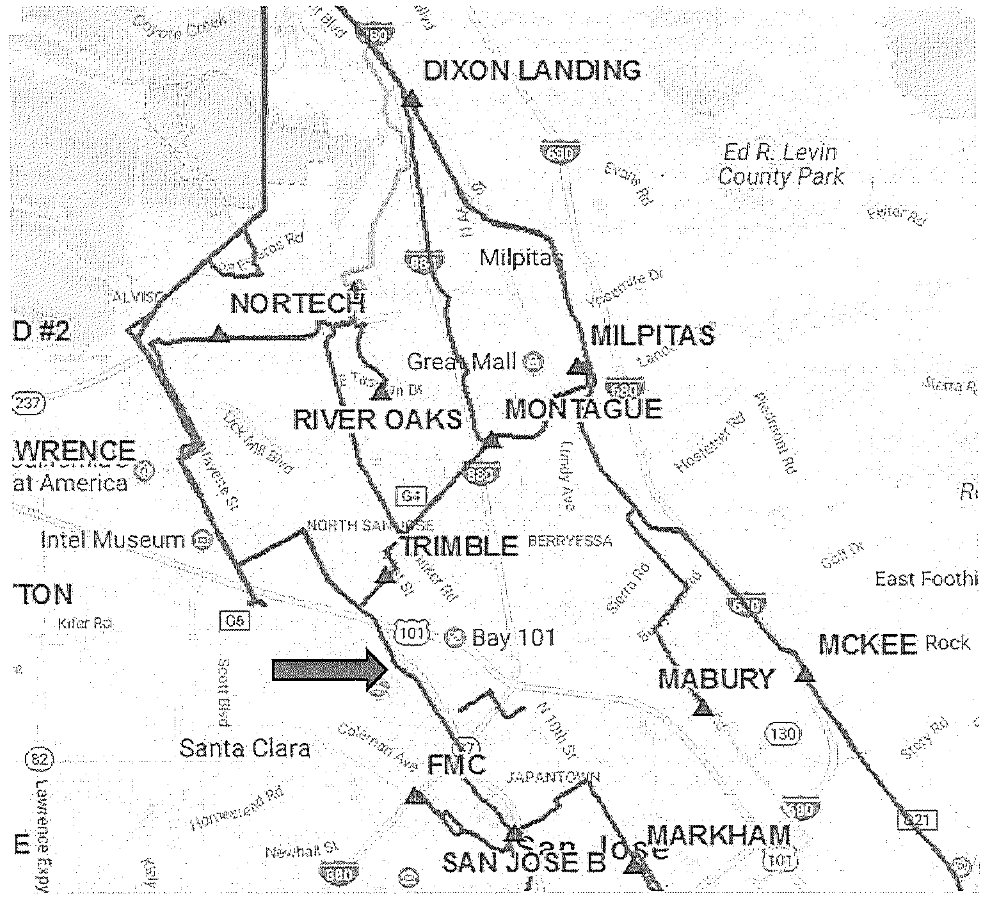
- Reliability Assessment Need
  - NERC Categories P6 starting 2019.
  - Overloads worsen in peak-shift and high CEC forecast sensitivities.
- Project Submitter
  - ISO
- Project Scope
  - Upgrade limiting equipment
    - circuit breaker at Newark
    - Terminal conductor
- Project Cost
  - $1.5M-$2M
- Alternatives Considered
  - Rerate
  - Battery energy Storage
- Recommendation
  - Approval



Map source: PG&E solar photovoltaic and renewable auction mechanism (PV RAM) project map

Trimble-San Jose B 115 kV Line Upgrade (Greater Bay Area)

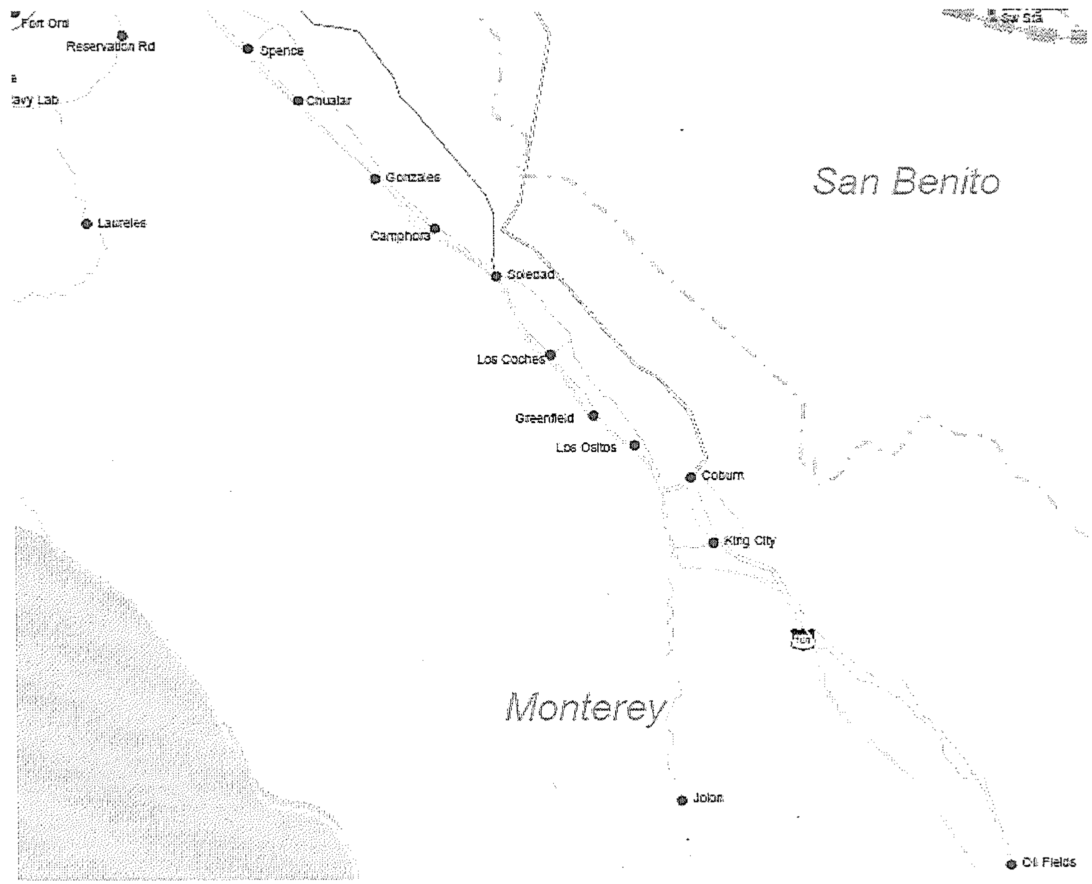
- Reliability Assessment Need
  - NERC Categories P6 starting 2022.
  - Overloads worsen in peak-shift and high CEC forecast sensitivities.
- Project Submitter
  - ISO
- Project Scope
  - Upgrade limiting equipment
    - circuit breaker at Newark
- Project Cost
  - $3M-$4M
- Alternatives Considered
  - Rerate
  - Battery Energy Storage
- Recommendation
  - Approval



Map source: PG&E solar photovoltaic and renewable auction mechanism (PV RAM) project map

Coburn-Oil fields 60 kV system (Central Coast / Los Padres)

- Reliability Assessment Need
  - NERC Categories P3.
- Project Submitter
  - PGAE
- Project Scope
  - Install 10 MVAR shunt capacitor at Oil Fields
- Project Cost
  - $7M-$10M
- Alternatives Considered
  - Local generation
- Recommendation
  - Approval



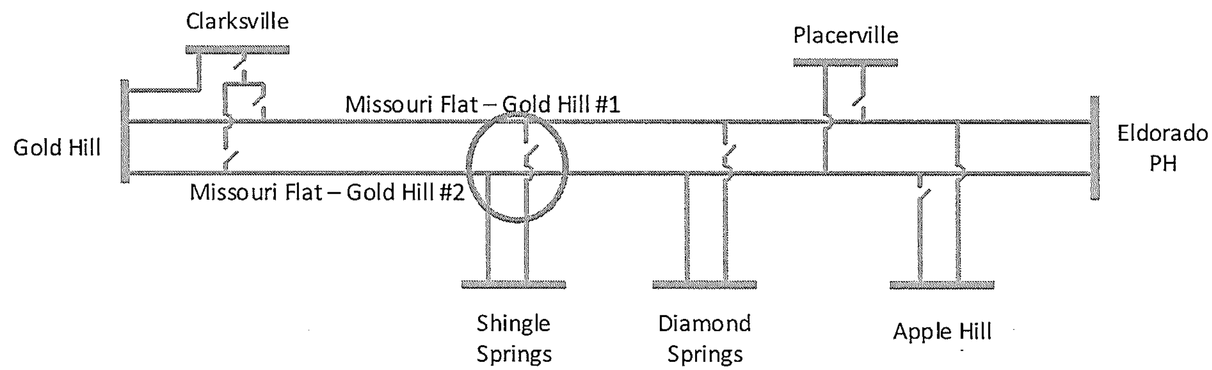
Map source: PG&E solar photovoltaic and renewable auction mechanism (PV RAM) project map

Shingle Springs Reconfiguration (Central Valley)

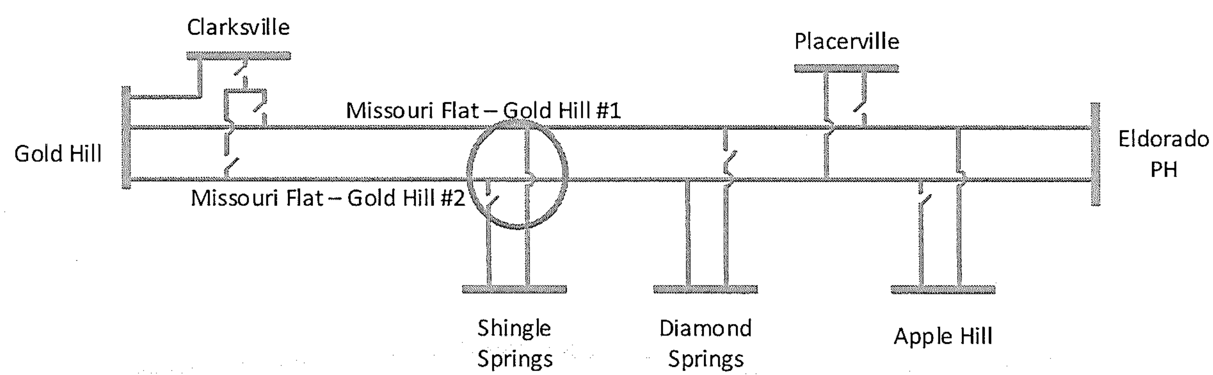
- Reliability Assessment Need
  - NERC Categories P2-1 thermal overloads on the Gold Hill to Eldorado 115 kV lines

- Recommendation
  - Move Shingle Springs load from Gold Hill – Missouri Flats #2 to #1

Existing configuration:



Recommended configuration:



Review of Previously Approved Projects

Previously Approved Transmission Projects

< 50M projects concluded at this time to proceed with current scope

Project Name	Area	Alternatives Considered	Reason
Metcalf-Evergreen 115 kV Line Reconductoring	Greater Bay Area	Power flow control device	Alternative doesn't resolve all reliability issues
Los Esteros 230 kV Substation Shunt Reactor	Greater Bay Area	None	No reasonable lower cost alternative available
Ravenswood – Cooley Landing 115 kV Line Reconductor	Greater Bay Area	•Cooley Landing 115 kV bus upgrade	•Doesn't resolve all overloads on this line
		•New 115 kV source to Palo Alto	•Palo Alto issues are addressed separately
		•Normally close tie between Ames and Monta Vista 115 kV systems.	•Doesn't resolve overloads on this line
Moraga-Castro Valley 230 kV Line Capacity Increase Project	Greater Bay Area	None	No reasonable lower cost alternative available
Glenn 230/60 kV Transformer No 1 Replacement	North Valley	None	BCR Project
Delevan 230 kV Substation Shunt Reactor	North Valley	None	No reasonable lower cost alternative available
Mosher Transmission Project	Central Valley	None	BCR Project
Vierra 115 kV Looping Project	Central Valley	None	No reasonable lower cost alternative available
Bellota 230 kV Substation Shunt Reactor	Central Valley	None	No reasonable lower cost alternative available
Ignacio 230 kV Substation Shunt Reactor	North Coast / North Bay	None	No reasonable lower cost alternative available
Wilson Voltage Support	Fresno	None	No reasonable lower cost alternative available
Midway-Temblor 115 kV Line Reconductor and Voltage Support	Kern	None	No reasonable lower cost alternative available
Wheeler Ridge Voltage Support	Kern	None	No reasonable lower cost alternative available

Previously Approved Transmission Projects

< 50M projects concluded at this time to be canceled

Projects recommended for cancelation without any further action

Project Name	Area	Reason
Los Esteros-Montague 115 kV Substation Equipment Upgrade	Greater Bay Area	No need identified
Evergreen-Mabury Conversion to 115 kV	Greater Bay Area	"Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade" project sufficient to address need
Glenn #1 60 kV Reconductoring	North Valley	No need identified
Napa – Tulucay No. 1 60 kV Line Upgrades	North Coast / North Bay	No need identified
Ashlan - Gregg and Ashlan - Herndon 230 kV Line Reconductor	Fresno	No need identified
Caruthers - Kingsburg 70 kV Line Reconductor	Fresno	No need identified
Kearney - Caruthers 70 kV Line Reconductor	Fresno	No need identified
Reedley 115/70 kV Transformer No. 2 Replacement Project	Fresno	No need identified

Projects recommended for cancelation with further action not requiring ISO approval

Project Name	Area	Further Action
Table Mountain – Sycamore 115 kV Line	North Valley	Recommend to PG&E to install an SPS
Stagg – Hammer 60 kV Line	Central Valley	Recommend to PG&E to install an SPS
Rio Oso – Atlantic 230 kV Line Project	Central Valley	Recommend to PG&E to upgrade protection and develop operating measure

Previously Approved Transmission Projects

< 50M projects concluded at this time to proceed with revised scope

Area	Project Name	Approved Project		Revised Scope	
		Original Scope	Cost (current estimate)	Revised Scope	Cost
GBA	NRS-Scott #1 115 kV line Reconductor	Reconductor NRS-Scott #1 115 kV line	$4M	Reconductor NRS-Scott #1 & #2 115 kV lines	$6M
NVLY	Cottonwood 115 kV Substation Shunt Reactor	Install a 100 Mvar shunt reactor at Cottonwood 115 kV bus	$17M-$19M	Replace existing 230/115 kV transformers with new transformers with LTC	$15M
NVLY	Cascade 115/60 kV No2 Transformer Project and Cascade – Benton 60 kV Line Project	•Cascade 115/60 kV Transformer No. 2 •High side breaker on the existing transformer •Cascade-Benton 60 kV line	$20M-$30M	•Cascade 115/60 kV Transformer No. 2 •High side breaker on the existing transformer	$10M-$20M
CVLY	Rio Oso Area 230 kV Voltage Support	•Rio Oso SVC (+200/-175Mvar) •Atlantic Capacitor bank	$30M-$40M	Rio Oso SVC(+200/-260Mvar)	$24M
CVLY	Pease 115/60 kV Transformer Addition and Bus Upgrade	•Pease transformer addition •Bus upgrade •UVLS in the interim	$30M	•Pease transformer addition •Bus upgrade •No UVLS	$30M
CVLY	Mosher Transmission Project (BCR project)	Reconductor the line with 2x715 AAC conductor	$10M-$20M	Reconductor the line with single 715 AAC conductor	$15M

Previously Approved Transmission Projects

< 50M projects concluded at this time to proceed with revised scope

Area	Project Name	Approved Project: Original Scope	Approved Project: Cost (current estimate)	Revised Scope: Revised Scope	Revised Scope: Cost
NCNB	Fulton-Fitch Mountain 60 kV Line Reconductor (Fulton-Hopland 60 kV Line)	Reconductor Fulton – Hopland 60 kV line	$29M	•Reconductor Fulton – Hopland 60 kV line •Re-rate another section of the Fulton – Hopland 60 kV Line •Re-rate the Fitch Mountain #2 60 kV Tap	$31M
NCNB	Clear Lake 60 kV System Reinforcement	•Build a new 115 kV line to Middletown Substation •Install a new 115/60 kV transformer at Middletown Substation	$50M	•Reconductor Clear Lake – Hopland 60 kV line •Install a 10-15 MVAR shunt capacitor at Middletown 60 kV substation	$14M
NCNB	Ignacio – Alto 60 kV Line Voltage Conversion	•Replace limiting equipment on the Ignacio- San Rafael No. 1 115 kV Line at the San Rafael Substation •Convert the Ignacio – Alto 60 kV Line from Ignacio Substation to Greenbrae Substation to 115 kV and loop the new 115 kV line into San Rafael Substation. •Install 20-30 MVAR shunt capacitor at Greenbrae 60 kV Substation	$50M	•Reconductor Ignacio- San Rafael #1 115 kV Line and Ignacio – Alto 60 kV Line •Add shunt capacitors at Greenbrae 60 kV Substation •Reconductor Ignacio- San Rafael #3 115 kV Line and upgrade limiting equipment.	$37M

Central California Study (2012-2013 Transmission Plan) Project Review

2012-2013 Transmission Plan
Central California Study

- The following was approved in the ISO 2012-2013 Transmission Plan to address the:
  - reliability needs of the Central California/Fresno area;
  - the pumping requirements of HELMs for area reliability; and
  - provide flexibility for the HELMs Pump Storage facility to provide ancillary services and renewable integration requirements.

Project	Current Estimated In-Service Date	Current Estimated Cost
Series Reactor on Warnerville-Wilson 230 kV Line	2017	$12 million
Gates #2 500/230 kV Transformer Addition	2022	$60 million
Kearney - Hearndon 230 kV Line Reconductoring	2019	$13 million
Gates-Gregg 230 kV Line	2022	$200 million

Reliability Need

- 2012-2013 Transmission Plan
  - Project was approved as a Reliability-driven project with potential renewable integration benefits
  - Reliability needs identified to start in the 2023 to 2029 timeframe

- 2016 and 2017 Assessment
  - The decreased local area "energy" needs and increased pumping opportunities have pushed the reliability need out 10 years, beyond the effective planning horizon, shifting the need from *Reliability Need* to *Renewable Integration Need*

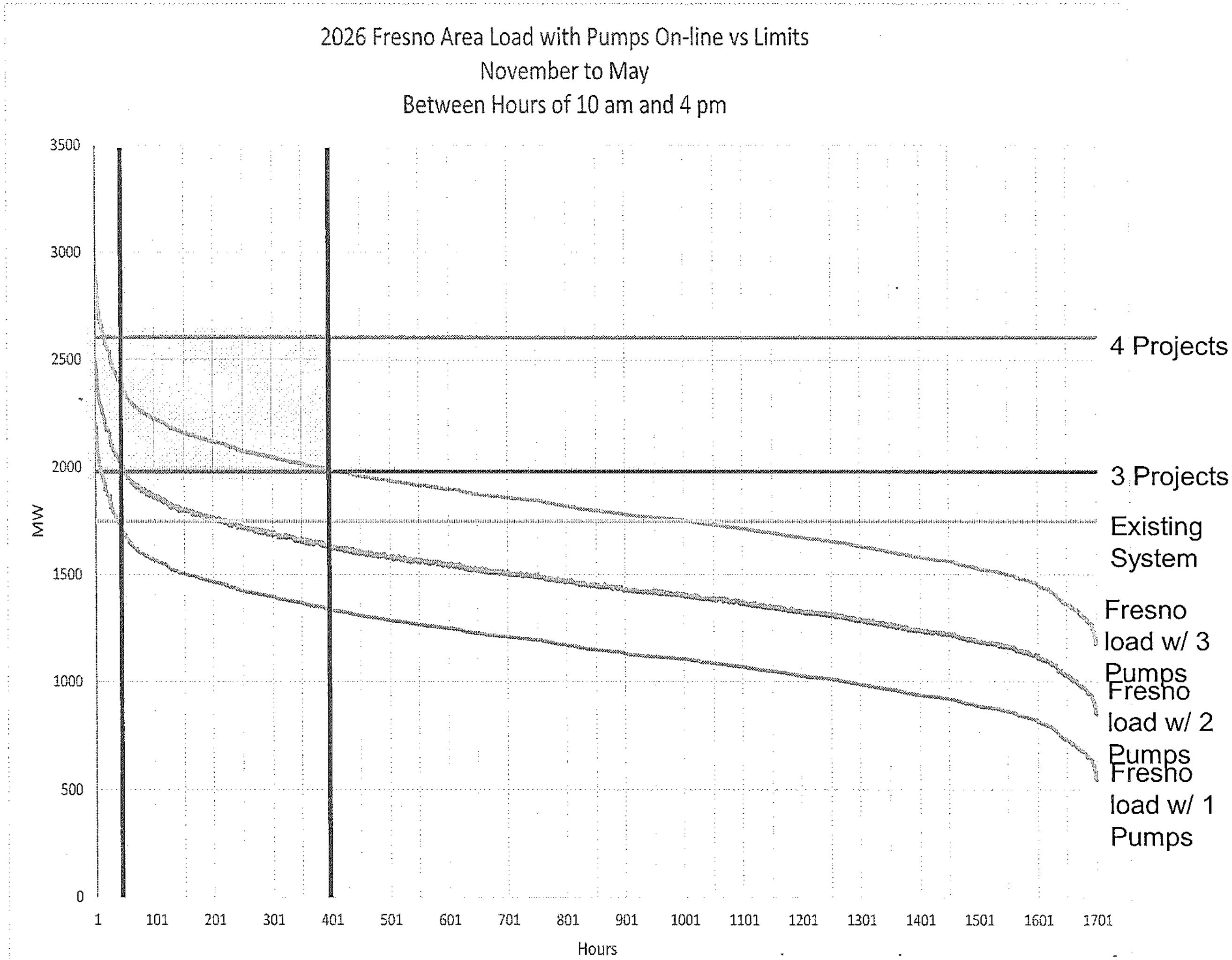
2026 Area Loads with Pumps versus Capability

(Non Summer Months – when oversupply conditions are expected)

2016-2017 TPP Assessment is still valid

- Load profile is similar
- BTM-PV in 2015 IEPR is consistent with the 2016 IEPR Update

ISO updating the detailed load forecast analysis based on 2017-2018 TPP



Uncertainty Could Impact Need

- Load Forecast
  - Distributed PV installed capacity and output
    - Increase in PV growth rate would decrease benefit
    - Reduction in PV growth rate would increase benefit
    - ***Note:*** *CEC Demand Analysis Work Group meeting on November 8 on the 2017 IEPR revised demand forecast indicates significant increase in Distributed PV*

    http://dawg.info/meetings/dawg-demand-forecasting-pup-2017-iepr-revised-demand-forecast-and-related-methodological
  - Load growth
    - Higher load growth and Fresno area forecast would increase benefit
    - Lower load growth and Fresno area forecast would decrease benefit
- Expanding over-supply timeframe to summer periods
  - Increase the benefits

Project Review Preliminary Assessment

Project	Assessment
Series Reactor on Warnerville-Wilson 230 kV Line	***Is required*** and is under construction with December 2017 in-service date
Gates #2 500/230 kV Transformer Addition	***Is required***. Generation deliverability in area is relying on upgrade, reliability issues identified in Bulk System studies and supports Helms pumping
Kearney - Hearndon 230 kV Line Reconductoring	***Further assessment still required; however appears to be required***. Supports Helms pumping and some congestion identified in economic assessment.
Gates-Gregg 230 kV Line	***Further assessment still required; however does not appears to be required.*** Supports Helms pumping.

Gates-Gregg 230 kV Transmission Line Project Next Steps

- At this time, there does not appear to be sufficient economic benefits to support the Gates-Gregg 230 kV Transmission Line Project

- ISO will update the detailed analysis and economic assessment based on cost of renewable curtailment in the draft ISO 2017-2018 Transmission Plan to be posted by January 31, 2018 for stakeholder comments.

- Based upon the assessment in the 2016-2017 TPP along with the preliminary assessment in the 2017-2018 TPP, the ISO is considering cancelling the Gates-Gregg 230 kV Transmission Line Project in the ISO 2017-2018 transmission planning process
  - The decision will be based upon the final updated assessment