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05/17/24
01:34 PM
R2305018

ATTACHMENT A
Phase 2 Staff Proposal

Staff Proposal for R.23-05-018 Phase 2 Updates to General Order 131-D

CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

May 2024

California Public
Utilities Commission

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Acknowledgements:

The authors appreciate the constructive comments provided by parties throughout the R.23-05-018 proceeding. In addition, the authors are grateful to CPUC Energy Division and Legal Division colleagues, including members of the CEQA and Energy Permitting, Infrastructure Planning and CEQA, and FERC Cost Recovery sections, for their thoughtful contributions to the development of this staff proposal. Finally, the authors would like to acknowledge the ongoing efforts of CEQA practitioners in the CPUC Energy Division and beyond to navigate the delicate balance of planning critical infrastructure while remaining responsive to the needs of communities, ratepayers, and the environment.

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Acronyms

AB: Assembly Bill

AFC: Application for certification

ALJ: Administrative law judge

BESS: Battery energy storage system(s)

CAISO: California Independent System Operator

CARB: California Air Resources Board

CCR: California Code of Regulations

CEC: California Energy Commission

CEQA: California Environmental Quality Act

CPUC: California Public Utilities Commission

CPCN: Certificate of public convenience and necessity

EIR: Environmental impact report

EMF: Electric and magnetic fields

FERC: Federal Energy Regulatory Commission

GO: General Order

GW: Gigawatt(s)

IOU: Investor-owned utility

IPP: Independent power producer

IRP: Integrated Resource Planning

IS: Initial study

kV: Kilovolt(s)

MND: Mitigated negative declaration

MW: Megawatt(s)

MWh: Megawatt-hour(s)

ND: Negative declaration

NEPA: National Environmental Policy Act

OIR: Order Instituting Rulemaking

PEA: Proponent's Environmental Assessment

PPA: Power purchase agreement

PRC: Public Resources Code

PTC: Permit to construct

PTO: Participating transmission owner

PUC: Public Utilities Code

ROW: Right-of-way

SB: Senate Bill

SRP: SCE Stakeholder Review Process

STAR: PG&E Stakeholder Transmission Asset Review Process

TDF: CAISO Transmission Development Forum

TPP: CAISO Transmission Planning Process

TPR Process: Transmission Project Review Process

1. Executive Summary

SUMMARY OF STAFF PROPOSAL

In this staff proposal, the California Public Utilities Commission (CPUC) Energy Division presents proposed modifications to the Commission's General Order (GO) 131-D in Phase 2 of the Rulemaking (R.)23-05-018 proceeding. The staff recommendations detailed in this staff proposal are based on a thorough review of the record and party comments, including the Joint Motion for Adoption of Phase 1 Settlement Agreement (settlement agreement), a proposed multi-party settlement filed by PG&E, SCE, and SDG&E on September 29, 2023. In developing this staff proposal, staff carefully reviewed and considered all party comments submitted during Phase 1 and Phase 2 of the R.23-05-018 proceeding along with party responses to R.23-05-018 Data Request 01 submitted in March 2024, which are included in Appendix C.

The purpose of the proposed modifications to GO 131-D is to accelerate the issuance of CPUC permits for electrical transmission facilities and related infrastructure. Taken together, these proposals are intended to clarify permitting requirements, reduce permitting timelines, ensure compliance with the California Environmental Quality Act (CEQA)[1], more efficiently provide CPUC staff with environmental permitting information necessary for CEQA review, minimize costs for ratepayers, and address proposals submitted by parties to the R.23-05-018 proceeding.

This staff proposal considers proposals developed by CPUC staff alongside proposals submitted by parties to the R.23-05-018 proceeding, including proposed revisions submitted in the settlement agreement. In developing this staff proposal, staff carefully reviewed and considered all party comments submitted during Phase 1 and Phase 2 of the R.23-05-018 proceeding along with party responses to R.23-05-018 Data Request 01 submitted in March 2024, which are included in Appendix C. The proposals are organized into eight issue categories, most of which contain multiple proposals, some of which in turn contain multiple options. Each issue is presented with a standard structure beginning with the problem statement followed by the proposals and options, the staff recommendations, and the rationale supporting the staff recommendations.

The proposals, staff recommendations, and rationale are discussed in detail in Section 3, Proposed Modifications to GO 131-D. Appendix A of this staff proposal contains a redline version of GO 131-D detailing the proposed Phase 2 revisions recommended by staff. Appendix B contains a clean version of GO 131-E with all the proposed Phase 2 revisions accepted.

CPUC Energy Division staff recommend the following modifications to GO 131-D and related actions:

- **Clarify Applicability of CPCN and PTC Exemptions** (Section 3.1)

[1] California Public Resources Code § 21000 *et seq*.

  - Define:
    - "Existing Electrical Transmission Facility"
    - "Extension", "Expansion", "Upgrade", and "Modification"
    - "Equivalent Facilities or Structures"
    - "Accessories"
  - Clarify applicability of:
    - PTC Exemption "g"
    - PTC Exemption "h"
- **Update Reporting Requirements** (Section 3.2)
  - Update:
    - Section V to Reference Existing Practice of Quarterly Briefings
    - Appendix A to Require Provision of Capital Costs and Other Financial Information
- **Establish Rebuttable Presumption in Favor of CAISO Transmission Plan** (Section 3.3)
  - Establish Rebuttable Presumption for CAISO-Approved Projects Pursuant to AB 1373
- **Clarify Advice Letter Protest Process** (Section 3.4)
  - Retain Executive Resolution Process and Clarify Appeal Process
- **Clarify Permitting of Battery Storage Facilities** (Section 3.5)
  - Clarify the permitting process for:
    - Transmission Lines Connecting to Battery Energy Storage Systems
    - Battery Energy Storage System Substation Upgrades
- **Facilitate ROW Sharing Between Incumbent and Non-Incumbent Utilities** (Section 3.6)
  - Further Consideration of Cal Advocates Proposal to Establish a ROW-Sharing Process for Incumbent and Non-Incumbent Utilities
- **Accelerate the CPCN and PTC Application Process** (Section 3.7)
  - Enable Applicant-Submitted Draft CEQA Documents
  - Consolidate EMF Requirements
  - Require Pre-Filing Consultation
- **Accelerate the CPUC CEQA Review Process** (Section 3.8)
  - Clarify Applicability of Existing CEQA Review Time Limits
  - Establish a Pilot Program for Accelerated CEQA Review
  - Further Consideration of Cal Advocates Proposal to Prioritize Policy-Driven CAISO TPP Projects

2. Introduction

2.1 Overview of General Order (GO) 131-D

2.1.1 Summary of Current GO 131-D

CPUC GO 131-D outlines rules for the permitting and construction of electrical transmission lines, power lines, distribution lines, substations, and electric generation facilities in California.

In Section III[2], GO 131-D identifies three categories of electrical infrastructure projects that are subject to CPUC authorization and/or public noticing requirements.

- **Certificate of Public Convenience and Necessity (CPCN):** GO 131-D Section III.A states that electrical transmission facilities designed to operate at 200 kilovolts (kV) or more and electric generating plants rated over 50 megawatts (MW)[3] shall not be constructed without the CPUC first issuing a certificate of public convenience and necessity (CPCN) unless the project constitutes an extension, expansion, upgrade, or other modification to an electric public utility's existing electrical transmission facilities or "the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing power line facilities, the conversion of existing overhead lines to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built".
- **Permit to Construct (PTC):** GO 131-D Section III.B stipulates that electrical power line facilities and substations designed for operation between 50 kV and 200 kV shall not be constructed without the CPUC first issuing a permit to construct (PTC) pursuant to Section IX.B. Pursuant to Section III.B.1, issuance of a PTC is not required for certain types of projects (except when any of the conditions listed in Section III.B.2 apply) provided that utilities file a Notice of Construction (NOC) as a Tier 2 advice letter pursuant to General Order (GO) 96-B.
- **Exempt Projects:** GO 131-D Sections III.A and III.B.1 outline various exemptions to the CPCN and PTC permitting requirements. Utilities must provide notice of the proposed construction of any projects that are deemed to be exempt from the PTC requirement pursuant to Section III.B.1, except that pursuant to Section III.B.1.h, projects that are statutorily or categorically exempt from

[2] All section references using Roman numerals (e.g., Section III, Section XI) are to GO 131-D unless otherwise specified.

[3] The Warren-Alquist State Energy Resources Conservation and Development Act of 1974 (Ca. Pub. Res. Code § 25000 et seq.) established the California Energy Commission (CEC) and required that prior to the construction or modification of an electric generating plant, the CEC was to certify the need for the plant and the suitability of the site of the plant—effectively making the CEC the lead agency for such projects rather than the CPUC. However, GO 131-D still includes processes for CPUC review of CEC-jurisdictional projects proposed by electric public utilities.

CEQA per the CEQA Guidelines (California Code of Regulations [CCR], Title 14, § 15000 et seq.) are exempt from the permitting and noticing requirements of GO 131-D. Additionally, Section III.C generally exempts electric distribution line facilities and substations under 50 kV and electric generating plants under 50 MW from the CPCN and PTC requirements.

In determining whether to issue a CPCN (i.e., for proposed projects that are not exempt from the CPCN requirement pursuant to Section III.A), the CPUC considers the environmental impacts of the proposed project pursuant to CEQA as well as the need for and cost of the proposed project. To issue a CPCN, the CPUC must find that the facilities are necessary to promote the safety, health, comfort, and convenience of the public, and are required by the public convenience and necessity. In determining whether to issue a PTC, the CPUC considers the environmental impacts of the proposed project pursuant to CEQA, but does not consider project need and cost to the extent required for a CPCN.

In addition to the permitting categories defined in Section III, GO 131-D also outlines utility reporting requirements (Sections IV, V, and VI), procedures for projects subject to the power plant siting jurisdiction of the California Energy Commission (CEC) (Section VII), CPCN and PTC application requirements(Sections VIII, IX, and X), public notice requirements (Section XI), protest and complaint procedures (Sections XII, XIII, and XIV), local agency preemption rules (Section XIV), procedures for coordinating with other state agencies (Section XV), and CEQA compliance requirements (Section XVI).

2.1.2 History of Modifications to GO 131

The CPUC first adopted GO 131 in 1970. The original version of GO 131 required a CPCN application for electric transmission lines rated over 200 kV and electric generation plants rated over 50 MW but did not include a PTC requirement.

In 1976, the CPUC adopted GO 131-A (amended in 1977), which, among other modifications, codified the transfer of load forecasting and generation siting authority to the CEC pursuant to the Warren-Alquist State Energy Resources Conservation and Development Act (California Public Resources Code Section 25000, Stats. 1974, Ch. 276).

In 1979, the CPUC adopted GO 131-B, which, among other modifications, incorporated amendments to the Warren-Alquist Act and provided for CPUC review of CPCNs for electric generation facilities concurrent with CEC review.

In 1985, the CPUC adopted GO 131-C, which, among other modifications, changed the financial reporting cadence outlined in Section IV (now Section VI in GO 131-D) from annual to biennial.

In 1994, the CPUC adopted GO 131-D with Decision (D.)94-06-014 (amended in 1995 and 2023), which established the PTC process for power lines designed to operate between 50 and 200 kV and for substations rated over 50 kV. Among other changes, GO 131-D also established new utility reporting requirements, introduced exemptions to the PTC requirement, eliminated the existing notice requirement for CEQA-exempt projects, and established a requirement that CPCN and PTC applications describe measures to reduce potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

In December 2023, the CPUC adopted an amended version of GO 131-D via D.23-12-035, as described in further detail in Section 2.2 of this staff proposal.

2.2 Legislative and Procedural Background

2.2.1 Overview

This staff proposal has been prepared in Phase 2 of CPUC Rulemaking 23-05-018 (R.23-05-018), a quasi-legislative proceeding to update GO 131-D. As described below, the Decision Addressing Phase 1 Issues (D.23-12-035) adopted in December 2023 amended GO 131-D to implement the statutory requirements of Senate Bill (SB) 529 (Hertzberg; Stats. 2022, Ch. 357) and to update outdated references. In Phase 2, the CPUC is considering all other potential changes to GO 131-D, including changes proposed by Commission staff and parties over the course of the proceeding.

2.2.2 Summary of R.23-05-018 Phase 1

Effective January 1, 2023, SB 529 added Public Utilities Code Section 564, which reads as follows:

> By January 1, 2024, the commission shall update General Order 131-D to authorize each public utility electrical corporation to use the permit-to-construct process or claim an exemption under Section III(B) of that general order to seek approval to construct an extension, expansion, upgrade, or other modification to its existing electrical transmission facilities, including electric transmission lines and substations within existing transmission easements, rights of way, or franchise agreements, irrespective of whether the electrical transmission facility is above a 200-kilovolt voltage level.

SB 529 also amended subsection (b) of Public Utilities Code Section 1001 to read as follows:

> The extension, expansion, upgrade, or other modification of an existing electrical transmission facility, including transmission lines and substations, does not require a certificate that the present or future public convenience and necessity requires or will require its construction.

On May 23, 2023, the CPUC issued an Order Instituting Rulemaking (OIR) which initiated R.23-05-018 to update and amend GO 131-D in accordance with SB 529 and to consider additional changes to GO 131-D to better address the needs of the State of California and its residents; maintain consistency with other applicable laws, policies, and Federal Energy Regulatory Commission (FERC) orders; and provide a clearer, more efficient, and more consistent process. The OIR elicited comments from stakeholders on a list of questions and two draft revised versions of GO 131-D. The first version, Attachment A of the OIR (OIR Attachment A), proposed amendments to GO 131-D solely to conform the GO to the requirements of SB

529. The second version, Attachment B of the OIR, included additional proposed amendments to GO 131-D beyond those outlined in Attachment A.

On June 21 and 22, 2023, the following parties filed opening comments on the OIR: Rural County Representatives of California (RCRC); the Acton Town Council; Clean Coalition; American Clean Power – California (American Clean Power); Pacific Gas and Electric Company (PG&E); California Farm Bureau Federation (Farm Bureau); the Protect Our Communities Foundation (POCF); Coalition of California Utility Employees (CUE); Environmental Defense Fund (EDF); California Energy Storage Alliance (CESA); Trans Bay Cable LLC, Horizon West Transmission, LLC, and GridLiance West LLC (jointly) (collectively, Transmission Owners); San Diego Gas & Electric Company (SDG&E); Defenders of Wildlife; the Public Advocates Office (Cal Advocates); Southern California Edison Company (SCE); Large-Scale Solar Association; LS Power Grid California, LLC (LS Power); California Independent System Operator Corporation (CAISO); Center for Energy Efficiency and Renewable Technologies (CEERT); REV Renewables; Independent Energy Producers Association (IEP); Liberty Utilities (CalPeco Electric) LLC, PacifiCorp, and Bear Valley Electric Service, Inc. (jointly) (collectively, California Association of Small and Multi-Jurisdictional Utilities (CASMU)); and the City of Long Beach, California, a municipal corporation acting by and through its Board of Harbor Commissioners (Long Beach).

On July 7, 2023, the following parties filed reply comments on the OIR: the Acton Town Council; American Clean Power; CAISO; Cal Advocates; CEERT; EDF; Farm Bureau; IEP; Large-Scale Solar Association; LS Power; PG&E; SCE; SDG&E; and Transmission Owners.

On July 31, 2023, the CPUC issued an Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) which set forth the issues, need for hearing, schedule, category, and other matters necessary to scope the proceeding. The Scoping Memo bifurcated the R.23-05-018 proceeding into two phases. Phase 1 was scoped to consider which changes to GO 131-D were necessary to conform it to the requirements of SB 529 and to update outdated references. In order to ensure compliance with the SB 529 deadline, Phase 1 was scoped to be completed on an expedited basis by January 1, 2024. Phase 2 was scoped to consider "all other changes to GO 131-D, including the changes proposed in attachments to the OIR, changes proposed by parties in comments on the OIR, and any additional changes that may be proposed by Commission staff or parties during the course of this proceeding". The Scoping Memo also provided that the proceeding would be resolved within 18 months of the issuance of the Scoping Memo, i.e., by January 31, 2025.

On September 29, 2023, San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE) filed a Joint Motion for Adoption of Phase 1 Settlement Agreement (settlement agreement) supported by 18 settling parties.[4] The settlement agreement outlined various proposed revisions to GO 131-D, including modifications described in this staff proposal in Section 3.3, Proposal 2; Section 3.4, Proposal 2; Section 3.7, Proposal 1; and Section 3.8, Proposal 1. The settlement agreement also included two attachments: Attachment A, which outlined the settling parties' key

[4] The settling parties are SCE, PG&E, SDG&E, Bear Valley Electric Service, Inc., Liberty Utilities (CalPeco Electric) LLC, PacifiCorp, American Clean Power, IEP, CEERT, EDF, LS Power, REV Renewables, Large-Scale Solar Association, CESA, Horizon West Transmission, LLC, Trans Bay Cable LLC, GridLiance West LLC, and Long Beach.

proposed modifications to GO 131-D, and Attachment B, which outlined additional proposed modifications contingent on the signing into law of several legislative bills that were still outstanding at the time the settlement agreement was submitted.

On December 14, 2023, the CPUC adopted an amended version of GO 131-D in its Decision Addressing Phase 1 Issues (D.23-12-035), concluding Phase 1 of the R.23-05-018 proceeding. The decision adopted modifications to GO 131-D to conform it to the requirements of Senate Bill 529 and to correct outdated references, but deferred consideration of all other issues to Phase 2, stating, "Several parties recommended additional modifications to GO 131-D, which are not required to implement SB 529. This decision is limited to addressing issues that are within the scope of Phase 1. Parties' additional recommendations shall be further considered during Phase 2." (D.23-12-035, December 14, 2023, at 6)

2.2.3 Summary of R.23-05-018 Phase 2

On December 18, 2023, the CPUC issued an Administrative Law Judges' (ALJs') Ruling Inviting Comment on Phase 2 Issues which invited parties to comment on four questions relating to the scope of proposed changes that should be considered in Phase 2, including questions focused on the Joint Motion for Adoption of Phase 1 Settlement Agreement and on defining key terms used in GO 131-D and Pub. Utilities Code Sections 564 and 1001(b). The ruling requested that opening comments be submitted by January 15, 2024 and that reply comments be submitted by January 29, 2024. On January 10, 2024, in response to requests from several parties, the CPUC issued a subsequent ruling extending the deadline for all respondents to February 5, 2024 for opening comments and to February 26, 2024 for reply comments.

On February 5, 2024, the following parties filed opening comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues: American Clean Power; Acton Town Council; Cal Advocates; CEERT; the Center for Biological Diversity, POCF, and Clean Coalition (jointly); CUE; EDF; Large-Scale Solar Association; Long Beach; PG&E; SCE; SDG&E; and the Sierra Club.

On February 26, 2024, the following parties filed reply comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues: American Clean Power; Acton Town Council; CAISO; Cal Advocates; CEERT; Center for Biological Diversity and POCF (jointly); CUE; EDF; Farm Bureau; IEP; Large-Scale Solar Association; LS Power; PG&E; RCRC; SCE; SDG&E; and the Sierra Club.

On January 29, 2024, Energy Division staff sent R.23-05-018 Data Request 01 (Data Request 01) to the following subset of parties in the R.23-05-018 proceeding: investor-owned utilities (IOUs), non-IOU participating transmission owners (PTOs), and other transmission developers and electric utilities. Data Request 01 included 11 questions, 10 of which were intended for all respondents and one of which was directed only to non-IOU PTOs and independent transmission developers. The questions focused on the project planning and application process; the provision of cost estimates; the CPCN and PTC exemption criteria; non-wires alternatives; and the implementation of the settlement agreement.

On March 8, 2024, the following parties submitted responses to R.23-05-018 Data Request 01: Bear Valley Electric Service; Horizon West Transmission, LLC; Liberty Utilities (CalPeco Electric) LLC; LS Power;

PacifiCorp; PG&E; SCE; and SDG&E. Selected data request responses are cited in this staff proposal and included for reference in Appendix C.

In developing this staff proposal, staff carefully reviewed and considered all party comments submitted during Phase 1 and Phase 2 of the R.23-05-018 proceeding, including the Joint Motion for Adoption of Phase 1 Settlement Agreement, along with party responses submitted in response to R.23-05-018 Data Request 01.

2.3 Overview of CEQA Review Pursuant to GO 131-D

The Commission's decision regarding whether or not to approve a CPCN or PTC constitutes a discretionary action that meets the definition of a "project" as defined under CEQA and requires the CPUC to review, disclose, and mitigate, to the extent feasible, any potentially significant environmental impacts of the proposed project pursuant to CEQA.

CEQA is codified in Public Resources Code (PRC) § 21000-21189. The "CEQA Guidelines" codified in California Code of Regulations (CCR), Title 14, § 15000 et seq. are regulations prescribed by the Secretary for Natural Resources to be followed by all state and local agencies in California in the implementation of CEQA. These Guidelines are binding on all public agencies in California (14 CCR 15000, Authority).

The legislative intent of CEQA is described in PRC Sections 21000 and 21001. PRC Section 21001(a) provides that it is the policy of the state to develop and maintain a high-quality environment now and in the future, and take all action necessary to protect, rehabilitate, and enhance the environmental quality of the state. PRC Section 21001(f) requires governmental agencies at all levels to develop standards and procedures necessary to protect environmental quality, while Section 21001(g) requires those agencies to consider qualitative, economic, and technical factors, long-term and short-term benefits and costs, and alternatives to proposed actions affecting the environment.

Section 21002 of CEQA states that public agencies should not approve projects as proposed if there are feasible alternatives or mitigation measures available which would substantially lessen any significant environmental effects of such projects. Depending on whether any significant impacts are anticipated, the CPUC, as the lead agency for CEQA review, may prepare an environmental impact report (EIR), mitigated negative declaration (MND), or negative declaration (ND). Section 21080I of CEQA provides direction regarding how to determine whether an EIR, MND, or ND should be prepared. In order to issue a CPCN or PTC, the CPUC must certify an EIR or adopt an MND or ND.

If a lead agency determines that a proposed project not otherwise exempt from CEQA would not have a significant effect on the environment, the lead agency shall adopt an ND to that effect. An MND is an ND prepared for a project when an initial study has identified potentially significant effects on the environment, but (1) revisions in the project plans or proposals made by, or agreed to by, the applicant before the proposed ND and initial study are released for public review would avoid the effects or mitigate the effects to a point where clearly no significant effect on the environment would occur, and (2) there is no substantial evidence in light of the whole record before the public agency that the project, as revised, may have a significant effect on the environment (PRC Section 21064.5).

If there is substantial evidence[5], in light of the whole record before the lead agency, that the project may have a significant effect on the environment, an EIR shall be prepared. In situations where a Final EIR identifies unmitigable significant environmental impacts, but where the CPUC determines that the approval of the project is in the public interest, the CPUC may certify the environmental document using a statement of overriding considerations, in which the CPUC states the reasons why the project should be approved despite the environmental impacts.

The CPCN and PTC processes do not neatly correspond to particular CEQA document types. The appropriate level of CEQA review is determined by each project's details and impacts, rather than by permit type. The CPCN process applies to higher-voltage projects that tend to be larger, cross jurisdictional boundaries and impact more resource areas and, accordingly, carry a greater potential for significant environmental impacts. As such, the CPUC has historically been more likely to prepare an EIR for CPCN projects, and an MND or ND for PTC projects. However, depending on factors such as environmental setting, initial evaluation of potential impacts, and level of public controversy, projects that qualify for a PTC may still require an EIR. The CPUC reviews CPCN applications under two parallel but largely bifurcated processes: an environmental review pursuant to CEQA, and a review of project need and costs pursuant to Public Utilities Code sections 1001 et seq. and Sections III.A and IX.A of GO 131-D.

Section 21082 of CEQA provides that public agencies must adopt their own objectives, criteria, and procedures for CEQA review. Rule 2.4 of the CPUC's Rules of Practice and Procedure establishes the CPUC's procedure for complying with CEQA and the CEQA Guidelines. Subsection (b) of Rule 2.4 states that any permit application for a project that is not statutorily or categorically exempt from CEQA shall include a Proponent's Environmental Assessment (PEA) prepared in accordance with the Commission's *Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments (Version 1.0, November 2019)*, herein referred to as the PEA Guidelines.

Pursuant to Section 15101 of the CEQA Guidelines, a lead agency or responsible agency shall determine whether an application for a permit or other entitlement for use is complete within 30 days from the receipt of the application. If no written determination of the completeness of the application is made within that period, the application will be deemed complete. Section 15102 of the CEQA Guidelines state that the lead agency shall determine within 30 days after accepting an application as complete whether it intends to prepare an EIR or ND or use a previously prepared EIR or ND. The 30-day period may be extended by 15 days upon the consent of the lead agency and the project applicant. Section 15060 of the CEQA Guidelines

[5] Pursuant to Section 21080(e) of CEQA, substantial evidence includes fact, a reasonable assumption predicated upon fact, or expert opinion supported by fact. Substantial evidence is not argument, speculation, unsubstantiated opinion or narrative, evidence that is clearly inaccurate or erroneous, or evidence of social or economic impacts that do not contribute to, or are not caused by, physical impacts on the environment.

states, "While conducting this review for completeness, the agency should be alert for environmental issues that might require preparation of an EIR or that may require additional explanation by the applicant. Accepting an application as complete does not limit the authority of the lead agency to require the applicant to submit additional information needed for environmental evaluation of the project. Requiring such additional information after the application is complete does not change the status of the application."

California Government Code Section 65940(a)(1) requires that each public agency compile one or more lists that shall specify in detail the information that will be required from any applicant for a development project. The PEA Guidelines contain detailed information that will be required from applications for development of energy projects submitted to the CPUC, including guidance to applicants, CPUC staff, and outside consultants regarding the type and detail of information needed to quickly and efficiently deem an application complete.

3. Proposed Modifications to GO 131-D

This section describes proposed modifications to GO 131-D for consideration in Phase 2 of the R.23-05-018 proceeding. Proposals are grouped within the following categories:

- Clarify Applicability of CPCN and PTC Exemptions
- Update Reporting Requirements
- Establish Rebuttable Presumption in Favor of CAISO Transmission Plan
- Clarify Advice Letter Protest Process
- Clarify Permitting of Battery Storage Facilities
- Facilitate ROW Sharing Between Incumbent and Non-Incumbent Utilities
- Accelerate the CPCN and PTC Application Process
- Accelerate the CPUC CEQA Review Process

Each issue category contains one or more proposals, some of which in turn contain multiple options. Each issue is presented with a standard structure beginning with the problem statement followed by the proposals and options, the staff recommendations, and the rationale supporting the staff recommendations.

The staff recommendations generally fall into three categories. In most cases, staff recommend the adoption of a particular proposal or one of the options listed within a proposal. In some instances, staff recommend further consideration of a proposal submitted by a party to the proceeding. Finally, there are several party-submitted proposals that are considered in this staff proposal, but which staff recommend against.

3.1 Clarify Applicability of CPCN and PTC Exemptions

3.1.1 Problem Statement

Section III.A. of GO 131-D establishes a requirement that electrical transmission projects designed for operation at 200 kV or more require a certificate of public convenience and necessity (CPCN), and outlines additional criteria whereby qualifying projects are exempt from the CPCN requirement. Section III.B establishes a requirement that electric power line and substation projects designed to operate between 50 and 200 kV (and new or upgraded substations with high-side voltage exceeding 50 kV) require a permit to construct (PTC), and outlines additional criteria whereby qualifying projects are exempt from the PTC requirement. However, certain key terms referenced in the CPCN and PTC exemption criteria are not defined in GO 131-D, leaving them open to interpretation. This section includes six proposals to clarify the applicability of various exemptions from the CPCN and PTC requirements.

In Decision 23-12-035, the CPUC modified Section III.A of GO 131-D to include the following paragraph implementing SB 529 and Public Utilities Code Sections 564 and 1001, allowing applicants to pursue the

PTC process or claim an exemption for projects constituting an "extension, expansion, upgrade, or other modification" to "existing electrical transmission facilities":

> In lieu of complying with Section III.A, an electric public utility is authorized to file a permit to construct application or claim an exemption under Section III.B to construct an extension, expansion, upgrade, or other modification to an electric public utility's existing electrical transmission facilities, including electric transmission lines and substations within existing transmission easements, rights of way, or franchise agreements, irrespective of whether the electrical transmission facility is above a 200-kV voltage level.

The new paragraph added to Section III.A adopts nearly verbatim the language used in SB 529 and Public Utilities Code Section 564. However, several key terms introduced in SB 529 remain open to interpretation: "extension", "expansion", "upgrade", "modification" and "existing electrical transmission facilities". The meaning of these terms is critical to the implementation of Section III.A, but the terms are not defined or otherwise explained in SB 529, Public Utilities Code section 564 or 1001, GO 131-D, or the R.23-05-018 Decision Addressing Phase 1 Issues (D.23-12-035), causing applicants to be uncertain about whether a particular project will require a CPCN. Clarifying the meaning of "extension", "expansion", "upgrade", "modification" and "existing electrical transmission facilities" in the text of GO 131-D, as discussed in Proposal 1 and Proposal 2, would provide applicants with clear criteria for project planning and would ensure consistent interpretation of Section III.A by Commission staff.

In the Decision Addressing Phase 1 Issues, the Commission directed that the definitions of "existing electrical transmission facility" be further considered during Phase 2 of the proceeding, and additionally directed staff to develop definitions of the terms "extension", "expansion", "upgrade", and "modification".

> We agree it would be useful to develop definitions or examples of the types of transmission projects that would qualify as an "extension, expansion, upgrade, or other modification." The record does not reflect a workable definition of these terms that would be consistent with SB 529. Therefore, we direct that Phase 2 of this proceeding include development of definitions of these terms. (D.23-12-035, December 14, 2023, at 14)

The proposals in this section also seek to clarify the meaning of two terms used in longstanding exemption criteria within Sections III.A and III.B of GO 131-D: "equivalent facilities or structures" and "accessories".

Section III.A of GO 131-D provides a list of criteria (predating SB 529) whereby qualifying projects do not require issuance of a CPCN. These criteria include "the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing power line facilities, the conversion of existing overhead lines to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built". Thus, applicants need not apply for a CPCN if they are replacing existing power line facilities or supporting structures with "equivalent facilities or structures", or if they are placing new or additional conductors, insulators, or their "accessories" on supporting structures already built. The term "equivalent facilities or structures" also appears in Section III.B.1.b, which exempts from the PTC requirement "the replacement of existing power line facilities or supporting structures with equivalent facilities or structures." Similarly, the term "accessories" appears in Section III.B.1.e, which exempts from the PTC requirement "the placing of new or additional conductors, insulators, or their accessories on supporting structures already built."

As written, the recurrent use of the terms "equivalent facilities or structures" and "accessories" in the CPCN and PTC exemptions provides a pathway for electric public utilities to provide notice of the construction of such facilities via a Tier 2 advice letter. However, these terms are not defined in GO 131-D, leaving their meaning open to interpretation. Clarifying the meaning of "equivalent facilities or structures" and "accessories" in the next version of GO 131-D would provide applicants with clear criteria to determine which projects may be noticed via advice letter, and would ensure consistent interpretation of the CPCN and PTC exemptions by Commission staff.

This section includes several options, outlined in Proposal 5, to clarify the applicability of GO 131-D Section III.B.1.g (PTC exemption "g"), which exempts from the PTC requirement "power line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility easement; or in a utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, state, or local agencies for which a final Negative Declaration or EIR finds no significant unavoidable environmental impacts." In 1997, the Commission's "Batiquitos" decision (D.97-03-058)[6] stated that there are two separate categories of exemption within Section III.B.1.g, as follows: "The semicolon, followed by the word "or," divides the potential locations of facilities listed in this section into two categories: 1) existing franchises, road-widening setback easements, or public utility easements; and 2) utility corridors officially adopted pursuant to law by federal, state, or local agencies for which a final negative declaration or EIR finds no significant unavoidable environmental impacts." (California Public Utilities Commission Decision 97-03-058, March 18, 1997) There is precedent for the Commission interpreting the first exemption "g" category to apply narrowly to power lines or substations to be located on land covered by one or more of the specific types of property right listed in the text of the exemption: existing franchises, road-widening setback easements, and public utility easements.[7]

In the Joint Motion for Adoption of Phase 1 Settlement Agreement submitted by PG&E, SCE, and SDG&E on September 29, 2023, the settling parties propose to clarify that the first exemption "g" category also includes power line facilities or substations to be located in an existing "right-of-way (ROW)", and to clarify that the second exemption "g" category applies specifically to "power line facilities or substations" to be located in a utility corridor. The term "right-of-way" is broader than the specific categories of property rights listed in the existing version of Section III.B.1.g. Franchise agreements and easements are both

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[6] Decision 97-03-058 was an order denying the rehearing of Decision 96-04-094 regarding the Commission's disposition of SDG&E Advice Letter 956-E for the Batiquitos Project, a 0.7-mile 138 kV underground transmission line to be installed entirely within an existing SDG&E franchise and an existing utility easement.

[7] In a non-standard disposition letter dated April 15, 2016 rejecting SCE Advice Letter 3356-E, Energy Division staff rejected SCE's request to construct the new Victor-Aqueduct 115-kV Subtransmission Tower Line Project pursuant to GO 131-D exemption "g", citing the rationale that the exemption did not apply because although portions of the project would be constructed in existing SCE easements, more than 94 percent of the project would be built on SCE fee-owned property, a category of property right not listed in Section III.B.1.g.

nonpossessory property rights that allow a utility to site, access, and maintain its infrastructure on property owned by another entity. However, "right-of-way" is a comparatively broad, undefined term that could conceivably refer to franchise agreements, easements, or any other usage right. Additionally, the qualifier "existing" does not distinguish temporally between longstanding land rights and those that a utility acquires expressly for the construction of new facilities, the latter of which might include undisturbed lands upon which utility infrastructure has not previously been sited. This ambiguity could pose implementation challenges by delegating authority to Commission staff to determine in an advice letter disposition whether a given project would be located in an "existing right-of-way", which can be difficult to independently verify.

The second exemption "g" category is not often cited. In responses to R.23-05-018 Data Request 01, PG&E, SCE, and SDG&E indicated that of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, none were located within a "utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies. (PG&E Response to R.23-05-018 Data Request 01, Question 7, March 8, 2024, at 1; SCE Response to Question 7 at 1; and SDG&E Response at 26-27) In its response to the same data request, Horizon West Transmission, LLC asserted that two projects from the 2022-2023 CAISO transmission plan are partially located within an applicable utility corridor: the North Gila – Imperial Valley 500 kV Transmission Line (more than 80% located within a Bureau of Land Management [BLM] Section 368 energy corridor [Section 368 corridor])[8] and the Imperial Valley – North of SONGS 500 kV Line and Substation (approximately 20% located within a Section 368 corridor). Horizon West Transmission, LLC suggests that while the North Gila – Imperial Valley project should qualify for the second exemption "g" category, the Imperial Valley – North of SONGS project would be unlikely to qualify. (Horizon West Transmission, LLC Response to R.23-05-018 Data Request 01, March 8, 2024, at 13)

Finally, this section includes several options, outlined in Proposal 6, to clarify the applicability of GO 131-D Section III.B.1.h (PTC exemption "h"), which exempts from the PTC requirement "the construction of projects that are statutorily or categorically exempt pursuant to § 15260 et seq. of the Guidelines adopted to implement the CEQA, 14 Code of California Regulations § 15000 et seq. (CEQA Guidelines)." The subsequent final paragraph of Section III.B.1 establishes that notice of the proposed construction of most PTC-exempt facilities must be made in compliance with Section XI.B of GO 131-D, "except that such notice is not required for the construction of projects that are statutorily or categorically exempt pursuant to CEQA Guidelines." As written, Section III.B.1.h and the final paragraph of Section III.B.1 could foreseeably enable a utility to independently determine that an activity meets the criteria for a statutory or categorical exemption, then construct the project without providing notice of the proposed construction, which would be inconsistent with CEQA. Section 15061 of the CEQA Guidelines clearly establishes that the lead agency is responsible for determining whether a project is exempt from CEQA, stating: "Once a lead agency has determined that an activity is a project subject to CEQA, a lead agency shall determine whether the project is exempt from CEQA." Section 15062(a) goes on to state, "When a public agency

[8] In accordance with Section 368(a) of the Energy Policy Act of 2005, the BLM has designated 5,000 miles of energy corridors ("Section 368 corridors," or "West-wide energy corridors") to locate future oil, natural gas and hydrogen pipelines, and electricity transmission and distribution infrastructure.

decides that a project is exempt from CEQA pursuant to Section 15061, and the public agency approves or determines to carry out the project, the agency may file a Notice of Exemption." The options outlined in Proposal 6 are intended to ensure that utilities provide appropriate notice of statutorily and categorically exempt projects pursuant to CEQA.

Utilities currently provide notice of PTC-exempt activities by submitting a Tier 2 advice letter pursuant to General Order (GO) 96-B. GO 96-B General Rule 5.1 explains that the advice letter process "provides a quick and simplified review of the types of utility requests that are expected neither to be controversial nor to raise important policy questions." There are three tiers of advice letter: Tier 1, Tier 2, and Tier 3. Tier 1 advice letters, which are effective pending disposition, typically involve simple, routine changes that have already been authorized by the CPUC. Tier 2 advice letters, which are effective after staff approval, typically involve minor proposals being made on the utility's own initiative, or more complicated matters already authorized by the CPUC. Tier 3 advice letters, which are effective after Commission approval via resolution pursuant to GO 96-B General Rule 7.6.2, are generally more complicated matters subject to discretionary approval. As explained in GO 96-B General Rule 7.6.1, "An advice letter is subject to disposition by the reviewing Industry Division whenever such disposition would be a "ministerial" act, as that term is used regarding advice letter review and disposition. (See Decision 02-02-049.)" GO 96-B Energy Industry Rule 5.2 currently states that a "request relating to a substation or power line under Section III.B.1 of General Order 131" is a matter appropriate to Tier 2 and therefore subject to disposition by Energy Division staff.

3.1.2 Proposals

Proposal 1: Define "Existing Electrical Transmission Facility"

This proposal would modify Section III.A of GO 131-D to add specificity to the term "existing electrical transmission facility", as used in Section III.A and Public Utilities Code sections 564 and 1001, by adopting the following definition:

> An "existing electrical transmission facility" is an electrical transmission line, power line, or substation that has been constructed for operation at or above 50 kV within an existing transmission easement, right of way, or franchise agreement.

Staff recommend adopting Proposal 1. The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 2: Define "Extension", "Expansion", "Upgrade", and "Modification"

This proposal would modify Section III.A of GO 131-D to add specificity to the terms "extension", "expansion", "upgrade", and "modification", as used in Section III.A and Public Utilities Code sections 564 and 1001. This staff proposal presents two options to define these terms.

- **Option 1** would adopt broad, overlapping definitions of the terms "extension", "expansion", "upgrade", and "modification".
- **Option 2** would adopt consolidated definitions of the terms "extension", "expansion", "upgrade", and "modification".

The specific definitions are detailed in Table 1 below. Staff recommend Option 1. The rationale for the staff recommendation is provided in Section 3.1.4 below.

Table 1. Options to Define "Extension", "Expansion", "Upgrade", and "Modification".

<table>
<tr><th>Term</th><th>Option 1</th><th>Option 2</th></tr>
<tr><td>Extension</td><td>An "extension" is:
1. An increase in the length of an existing electrical transmission facility within existing transmission easements, rights-of-way, or franchise agreements; or
2. One of the following types of projects:
a. Generation tie-line (gen-tie) segments, i.e., the construction of a new transmission or power line from an existing electrical transmission facility to connect to a new energy storage or generation facility (i.e., the portion of the new line that will be owned by the transmission operator); or
b. Substation loop-ins, i.e., an incumbent utility looping existing transmission lines into and out of a new CAISO-approved third-party substation if the developer of the substation is required to file a CPCN application (because its scope includes a major new over-200 kV line as well as the substation) and the incumbent utility's scope is limited to looping several of its existing transmission lines into and out of the new substation.</td><td>An "extension" or "expansion" is an increase in the length of an existing electrical transmission facility, or one of the following types of projects:
1. Generation tie-line (gen-tie) segments, i.e., the construction of a new transmission or power line from an existing electrical transmission facility to connect to a new energy storage or generation facility (i.e., the portion of the new line that will be owned by the transmission operator)
2. Substation loop-ins, i.e., an incumbent utility looping existing transmission lines into and out of a new CAISO-approved third-party substation if the developer of the substation is required to file a CPCN application (because its scope includes a major new over-200 kV line as well as the substation) and the incumbent utility's scope is limited to looping several of its existing transmission lines into and out of the new substation.</td></tr>
</table>

Expansion	An "expansion" is an increase in the width, capacity, or capability of an existing electrical transmission facility, including but not limited to the following types of projects: 1. Rewiring or reconductoring to increase the capacity of an existing transmission line 2. Expanding the carrying capacity of existing towers 3. Converting a single-circuit transmission line to a double-circuit line to expand the quantity or capacity of the existing transmission line facilities	
Upgrade	An "upgrade" is the replacement or alteration of existing electrical transmission facilities, or components thereof, to enhance the rating, voltage, capacity, capability, or quality of those facilities, including but not limited to the following types of projects: 1. Reconductoring existing lines to use conductors with greater power transfer capability and/or increased voltage levels, where the reconductoring requires replacement of the existing supporting structures 2. Adding smart grid capabilities to an existing line, or other wildfire hardening measures 3. Installation of new mid-line series capacitors on a transmission line to support an increase in the power transfer capability of the line 4. Replacing existing support structures with new support structures of a different material and/or design 5. Adding battery energy storage systems to an existing substation, or expanding	An "upgrade" or "modification" is the replacement or alteration of an existing electrical transmission facility without extending or expanding the physical footprint of the facility, including but not limited to the following types of projects: 1. Converting a single-circuit transmission line to a double-circuit line 2. Reconductoring existing lines to use conductors with greater power transfer capability and/or increased voltage levels, where the reconductoring requires replacement of the existing supporting structures 3. Adding smart grid capabilities to an existing line, or other wildfire hardening measures 4. Installation of new mid-line series capacitors on a transmission line to support an increase in the power transfer capability of the line 5. Replacing existing support structures with new support structures of a different material and/or design

	an existing substation to include battery energy storage systems 6. Replacing or adding equipment (e.g., circuit breakers, transformers) to a substation for the purpose of uprating the substation; or the uprating of individual components of a transmission line, power line, or substation	6. Replacing or adding equipment (e.g., circuit breakers, transformers) to a substation for the purpose of uprating the substation; or the uprating of individual components of a transmission line, power line, or substation
Modification	A "modification" is a change to an existing electrical transmission facility or equipment to serve a new or additional purpose without extending or expanding the physical footprint of the facility.	

Staff recommend Option 1, which would define "extension", "expansion", "upgrade", and "modification" by adopting separate but overlapping definitions. The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 3: Define "Equivalent Facilities or Structures"

This proposal would modify Section III.A of GO 131-D to add specificity to the term "equivalent facilities or structures", as used Sections III.A and III.B.1.b, by adopting the following definition:

> "Equivalent facilities or structures" are new power line facilities or supporting structures that are installed to replace existing power line facilities or supporting structures and that provide power transfer capability at no greater voltage than the facilities or structures being replaced.

Staff recommend adopting Proposal 3. The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 4: Define "Accessories"

This proposal would modify Section III.A of GO 131-D to add specificity to the term "accessories", as used in Sections III.A and III.B.1.e, by adopting the following definition:

> "Accessories" are transmission line, power line, or substation equipment required for the safe and reliable operation of the transmission system, including but not limited to switches, connectors, relays, real-time monitoring equipment (e.g., telemetry, SCADA), and control shelters.

Staff recommend adopting Proposal 4. The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 5: Clarify Applicability of PTC Exemption "g"

This proposal would modify Section III.B.1.g of GO 131-D to clarify the applicability of PTC exemption "g" described therein. With the deletion of Section III.B.1.a—see Appendix A, Proposed Revisions to GO 131-D to Address R.23-05-018 Phase 2 Issues (Redline)—Section III.B.1.g would become III.B.1.f.

Option 1: Modify Section III.B.1.g to clarify that the first clause would apply to power line facilities or substations to be located "in an existing right-of-way (ROW) containing existing power line facilities or substations", and that the second clause would apply to a power line or substation proposed in a government-adopted utility corridor where a prior CEQA document found no significant unavoidable impacts. The revised text of Section III.B.1.g would read as follows, with new text underlined in red and deletions in red strikethrough.

g. power line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility easement, or in an existing right-of-way (ROW) containing existing power line facilities or substations; or power line facilities or substations in a utility corridor designated, precisely mapped, and officially adopted pursuant to law by federal, State, or local agencies for which a final ~~Negative Declaration or~~ EIR, MND, or ND finds no significant unavoidable environmental impacts.

Option 2: Modify Section III.B.1.g as proposed by settling parties (in the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by PG&E, SCE, and SDG&E on September 29, 2023) to clarify that the first clause would apply to power line facilities or substations to be located in an existing "public right-of-way (ROW) or easement", and that the second clause would apply to a power line or substation proposed in a government-adopted utility corridor where a prior CEQA document found no significant unavoidable impacts. The revised text of Section III.B.1.g would read as follows, with new text underlined in red and deletions in red strikethrough.

g. power line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility right-of-way (ROW) or easement; or power line facilities or substations in a utility corridor designated, precisely mapped, and officially adopted pursuant to law by federal, State, or local agencies for which a final ~~Negative Declaration or~~ EIR, MND, or ND finds no significant unavoidable environmental impacts.

Staff recommend Option 1, which would modify Section III.B.1.g to clarify that the first clause would apply to power line facilities or substations to be located "in an existing right-of-way (ROW) containing existing power line facilities or substations", and that the second clause would apply to a power line or substation proposed in a government-adopted utility corridor where a prior CEQA document found no significant unavoidable impacts. The rationale for the staff recommendation is provided in Section 3.1.4 below

Proposal 6: Clarify Applicability of PTC Exemption "h"

This proposal would modify the final paragraph of Section III.B.1 to ensure that appropriate notice is provided pursuant to CEQA for the construction of projects subject to Section III.B.1.h, which exempts from the PTC requirement any projects that are statutorily or categorically exempt from CEQA. With the deletion of Section III.B.1.a—see Appendix A, Proposed Revisions to GO 131-D to Address R.23-05-018 Phase 2 Issues (Redline)—Section III.B.1.h would become III.B.1.g.

Option 1: Modify Section III.B.1 of GO 131-D to require notice via an information-only submittal pursuant to GO 96-B for projects that are statutorily or categorically exempt from CEQA rather than via a Tier 2 advice letter as typically required for GO 131 Section III.B.1 requests pursuant to Energy Industry Rule 5.2 of the Commission's Rules of Practice and Procedure.

The text of the final paragraph of Section III.B.1 would be revised as follows, with additions underlined in red and deletions in red strikethrough:

4. ~~However~~ When a PTC is not required based on the exemptions above, notice of the proposed construction of such facilities must be made in compliance with Section ~~XI.B herein~~ X.B below, except that ~~such~~ notice ~~is not required for~~ of the proposed construction of projects that are statutorily or categorically exempt pursuant to the CEQA Guidelines must be made through an information-only submittal pursuant to General Order 96-B or its successor regulation. The information-only submittal shall include the level of information that would be included in an advice letter, but shall neither seek relief nor be subject to protest, pursuant to General Order 96-B, General Rule 6.2.

5. If a protest of the construction of facilities claimed by the utility to be exempt from compliance with Section ~~I~~X.B is timely filed pursuant to Section XII~~I~~, construction may not commence until the Executive Director or Commission has issued a final determination.

Pursuant to GO 96-B, General Rule 3.9, an "information-only submittal" means "an informal report, required by statute or Commission order, that is submitted by a utility to the Commission, but that is not submitted in connection with a request for Commission approval, authorization, or other relief", and may be either a periodic or an occasional report.

Pursuant to GO 96-B, General Rule 6.2, since information-only submittals do not seek relief, they are not subject to protest, as provided for applications and advice letters. However, the reviewing Industry Division (i.e., the Energy Division, in the case of GO 131-D) may notify the utility of any omission or other defect in a submittal, and the utility shall remedy such defect within a reasonable time. A utility that fails to remedy defects or fails to submit a required report on time or at all shall be subject to fines and other sanctions.

Option 2: Modify Section III.B.1 of GO 131-D to require notice via a Tier 2 advice letter of projects that are statutorily or categorically exempt from CEQA as required for other GO 131 Section III.B.1 projects pursuant to Energy Industry Rule 5.2 of the Commission's Rules of Practice and Procedure.

The text of Section III.B.1 would be revised as follows, with additions underlined in red and deletions in red strikethrough:

4. ~~However~~ When a PTC is not required based on the exemptions above, notice of the proposed construction of such facilities must be made in compliance with Section ~~XI.B herein~~ X.B below.
5. If a protest of the construction of facilities claimed by the utility to be exempt from compliance with Section ~~I~~X.B is timely filed pursuant to Section XII~~I~~, construction may not commence until the Executive Director or Commission has issued a final determination.

Option 3: No action. Do not modify Section III.B.1.h of GO 131-D or the text "except that such notice is not required for the construction of projects that are statutorily or categorically exempt pursuant to CEQA Guidelines" in Section III.B.1.

Staff recommend adoption of Option 1, which would modify Section III.B.1 of GO 131-D to require notice via an information-only submittal pursuant to GO 96-B for projects that are statutorily or categorically exempt from CEQA rather than via a Tier 2 advice letter as typically required for GO 131 Section III.B.1 requests pursuant to Energy Industry Rule 5.2 of the Commission's Rules of Practice and Procedure. The rationale for the staff recommendation is provided in Section 3.1.4 below.

3.1.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1: Staff recommend adoption of Proposal 1, which would define an "existing electrical transmission facility" as "an electrical transmission line, power line, or substation that has been constructed for operation at or above 50 kV within an existing transmission easement, right of way, or franchise agreement." The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 2, Option 1: Staff recommend adoption of Proposal 2, Option 1, which would define "extension", "expansion", "upgrade", and "modification" by adopting the separate but overlapping definitions outlined in Option 1. The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 3: Staff recommend adoption of Proposal 3, which would "equivalent facilities and structures" as "new power line facilities or supporting structures that are installed to replace existing power line facilities or supporting structures and that provide power transfer capability at no greater voltage than the facilities or structures being replaced." The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 4: Staff recommend adoption of Proposal 4, which would define "accessories" as "transmission line, power line, or substation equipment required for the safe and reliable operation of the transmission system, including but not limited to switches, connectors, relays, real-time monitoring equipment (e.g., telemetry, SCADA), and control shelters." The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 5, Option 1: Staff recommend adoption of Proposal 5, Option 1, which would modify Section III.B.1.g to clarify that the first clause would apply to power line facilities or substations to be located "in an existing right-of-way (ROW) containing existing power line facilities or substations", and that the second clause would apply to a power line or substation proposed in a government-adopted utility corridor where a prior CEQA document found no significant unavoidable impacts. The rationale for the staff recommendation is provided in Section 3.1.4 below.

Proposal 6, Option 1: Staff recommend adoption of Proposal 6, Option 1, which would modify Section III.B.1 of GO 131-D to require notice via an information-only submittal pursuant to GO 96-B for projects that are statutorily or categorically exempt from CEQA rather than via a Tier 2 advice letter as typically required for GO 131 Section III.B.1 requests pursuant to Energy Industry Rule 5.2 of the Commission's Rules of Practice and Procedure. The rationale for the staff recommendation is provided in Section 3.1.4 below.

3.1.4 Rationale for Staff Recommendations

Staff recommend Proposal 1 for the following reasons:

- **Defining "existing electrical transmission facilities" would improve clarity for applicants and reduce the need for case-by-case interpretation.** Defining "existing electrical transmission facilities" would provide clarity to applicants regarding which projects are eligible for the SB 529 process whereby applicants can file a PTC application or claim an exemption for certain projects previously covered by the CPCN requirement. Additionally, consistent application of the SB 529 process to projects constituting an "extension", "expansion", "upgrade", or "modification" of existing electrical transmission facilities will rely on a clear definition of "existing electrical transmission facilities". A range of parties including the Sierra Club and Cal Advocates support defining "existing electrical transmission facilities" in the text of Section III.A.
  - Cal Advocates asserts, "In short, General Order (GO) 131-D should be amended to further define the term "existing facility." If it is not, the term could be read to mean that any project qualifies for a Permit to Construct (PTC), as long as the project relates to an existing facility. Such an interpretation would render the remainder of the Certificate of Public Convenience and Necessity (CPCN) requirement under GO 131-D Section III.A meaningless because an applicant with existing electric facilities would never need to apply for a CPCN unless the proposed new project had no relation to existing facilities. That would be inconsistent with the established rule that "a court should ordinarily reject interpretations that render particular terms of a statute mere surplusage; instead, the court should give every word some significance." (*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruing Inviting Comment on Phase 2 Issues*, February 5, 2024, at 2)
  - The Sierra Club states, "For purposes of Section 564 and Section III.A of GO 131-D, Sierra Club proposes that the term "existing electrical transmission facilities" be defined as follows … Sierra Club proposes that this definition be expressly included in Section III.A of GO

131-D. Sierra Club reached this proposal in part based on consultation with the Center for Biological Diversity, Protect Our Communities Foundation, and Clean Coalition." (*Sierra Club Opening Comments on Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 2)

- **A range of parties support a definition that includes "power lines" and "substations".** Parties to the R.23-05-018 proceeding have generally expressed support for a definition of "existing electrical transmission facilities" that includes facilities rated 50 kV or greater (i.e., "transmission lines", "power lines", and "substations", as defined in Section I of GO 131-D) to enable applicants to pursue the SB 529 process for projects where an existing 50-200 kV power line is being modified into an over-200 kV transmission line. The Commission invited party input on this question in Question 1 of the ALJs' Ruling Inviting Comments on Phase 2 Issues issued December 18, 2023. Although the Acton Town Council argued against including any facilities below 200 kV, the following parties expressed support for including 50-200 kV facilities: EDF, PG&E, SCE, SDG&E, and the Sierra Club.
  - In its 1994 decision adopting the original version of GO 131-D, the Commission stated that facilities over 50 kV can be considered "transmission": "The 50-kV limit is the cutoff point between lines serving transmission functions (50 kV and over) and those serving distribution functions (under 50 kV)." (CPUC Decision 95-06-014 at 25)
  - EDF asserts, "Second, should modification of a facility between 50 kV and 200 kV to a 500 kV facility qualify for the permitting process authorized in SB 529? The answer is yes. This project would be for construction "of [a] major electric transmission line facilit[y] which [is] designed for immediate or eventual operation at 200 kV or more" under the first paragraph of Section III.A. And under the second paragraph of Section III.A, it would qualify to apply for a PTC or claim an exemption as a modification of an existing electrical transmission facility." (*Comments of Environmental Defense Fund on Phase 2 Issues*, February 5, 2024, at 4)
  - The Sierra Club asserts, "The [Sierra Club's] proposed definition also reflects the distinction that electrical conveyance facilities with a carrying capacity below 50 kV are considered to be "distribution," while electrical conveyance facilities with a carrying capacity above 50 kV are considered to be "transmission."" (*Sierra Club Opening Comments on Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 2)
  - SDG&E asserts, "The Commission has recognized and adopted the common industry definition of transmission facilities as facilities that operate at or above 50 kV. When it adopted GO 131-D, the Commission recognized that lines between 50 kV and 200 kV are "transmission lines." It adopted the definitions of "transmission line" and "power line" in GO 131-D simply to distinguish the transmission lines subject to CPCN requirements from those subject to PTC requirements." (*SDG&E Reply Comments to ALJs' Ruling Inviting Comments on Phase 2 Issues*, February 26, 2024, at 14)
  - As PG&E asserts in its reply comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues, the Acton Town Council was the only party that argued against using 50 kV as the cutoff point for the SB 529 process: "Only one party argues otherwise – Acton Town Council ("ATC"). [ATC] insists that the existing facilities being "extended, expanded, upgraded or modified" must first be over 200 kV to qualify for the exemption, even if a

below-200 kV line is being upgraded to a voltage over 200 kV. To support this proposition, ATC asserts that "the California Assembly actually defined the term 'transmission line' to mean an 'electric line' that operates at '200 kilovolts or more.'" The Assembly did no such thing. Rather, the summary drafted by legislative staff observed that electrical lines over 200 kV are "often known as transmission lines" (which is true, in part) and that lines between 50-200 kV voltage are "often known as distribution lines" (which is not). … Equally misleading, ACT's quote from the California Senate Analysis that "[e]lectric transmission lines are generally high voltage lines that move electricity from generation resources (power plants)" does not finish the sentence, which reads "to distribution lines in neighborhoods" and makes PG&E's point that "transmission" in this context (and in general utility practice) is everything that isn't distribution (i.e., everything over 50 kV). In truth, the legislative history of SB 529 is variable and simply did not address whether converting an existing under-200 kV line to over 200 kV would fall within the proposed exemption. Fortunately, the plain language in PUC Section 564 governs, and prohibits looking further." (*Reply Comments of Pacific Gas and Electric Company (U 39-E) on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 3-4)

- **A range of parties support limiting the SB 529 process to facilities "within existing transmission easements, rights of way, or franchise agreements".** In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties assert that the word "including" is not restrictive as used in SB 529 in the statement "existing electrical transmission facilities, including electric transmission lines and substations within existing transmission easements, rights of way, or franchise agreements", an interpretation which would support a definition that includes a broader range of eligible facilities. However, a range of other parties (Acton Town Council, Cal Advocates, the Center for Biological Diversity, Farm Bureau, Sierra Club, POCF, and Clean Coalition) argue that the term "including" is restrictive, and that the SB 529 process should be limited to facilities "within existing transmission easements, rights of way, or franchise agreements".
    - The Acton Town Council asserts, "What SB 529 *actually* says is that utilities are authorized to "use the permit-to-construct process or claim an exemption under Section III(B) of that general order to seek approval to construct an extension, expansion, upgrade, or other modification to its existing electrical transmission facilities, *including electric transmission lines and substations within existing transmission easements, rights of way, or franchise agreements, irrespective of whether the electrical transmission facility is above a 200-kilovolt voltage level.*" (emphasis added). The Supreme Court has long held that the term "includes" is a term of limitation and not enlargement; where it is used, it prescribes all of the things or classes of things to which the statute pertains and it excludes by implication all other possible objects of the statute. Accordingly, and contrary to what SDGE argues, the use of the PTC process for extensions to existing transmission facilities is expressly limited by SB 529 to only activities involving existing transmission easements and rights of way. (*Reply Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 37)
    - The Center for Biological Diversity, POCF, and the Clean Coalition (jointly) state that an extension (as used in Section 564 and Section III.A of GO 131-D) should be defined as

"policy-driven construction, within an existing easement, right of way, or franchise agreement, of an electric transmission or power line facility that connects an existing electric transmission facility to a service delivery point and does not have a significant effect on the environment or rates." (*Opening Comments of the Center for Biological Diversity, the Clean Coalition and The Protect Our Communities Foundation on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 10)

- Cal Advocates states, "'Extension' should be defined as the addition of new transmission lines, power lines, or distribution lines to new or existing generators or substations located within existing transmission easements, rights of way, or franchise agreements and within a designated maximum length continuing directly from the terminus of existing transmission lines."(*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 6)
- The Sierra Club states, "Sierra Club cannot envision, and SDG&E's comments do not identify, any type or size of transmission facility that would *not* be classified as an extension under this proposed definition by virtue of being connected to the grid. SDG&E's proposed definition of "extension" would effectively encompass *all* new transmission facilities, thereby eliminating *de facto* all transmission-related CPCN review. Such an outcome is inconsistent with the text of California Public Utilities Code Section 564, with core principles of statutory interpretation, and with the legislative purpose of SB 529." (*Sierra Club Reply Comments on Ruling Inviting Comment on Phase 2 Issues,* February 26, 2024, at 7-8). The Sierra Club goes on to state, "However, SCE proposes a somewhat broader definition of expansion as "[a] project that results in longer, larger or additional facilities or right-of-way." (*Sierra Club Reply Comments on Ruling Inviting Comment on Phase 2 Issues,* February 26, 2024, at 11)

- **A range of parties have expressed agreement that "existing electrical transmission facilities" must physically exist or be constructed.** CUE, PG&E, SCE, SDG&E, and the Sierra Club separately recommend, in their opening comments on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues, that the term "existing electrical transmission facilities" should include facilities that are physically constructed or installed.
  - Southern California Edison Company recommends the term "existing electrical transmission facilities" include "Any electrical infrastructure designed for operation at voltage levels above 50 kV that has already been constructed or installed, regardless of whether currently in operation." (*Opening Comments of the Southern California Edison Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 2)
  - Pacific Gas and Electric Company suggests using the plain meaning of "existing electrical facilities" to be any electrical facilities physically in place, regardless of operating or permitting status…." (*Opening Comments of the Pacific Gas and Electric Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 2)
- **The question of whether existing electrical transmission facilities must be "operational" or exclude "property under utility control upon which no electrical infrastructure is currently located" was addressed in the Decision Addressing Phase 1 Issues (D.23-12-035).** R.23-05-018 OIR Attachment A proposed to define an existing electrical transmission facility as "existing,

operational electrical infrastructure" that "does not include property under utility control upon which no electrical infrastructure is currently located." However, in the Decision Addressing Phase 1 Issues (D.23-12-035), the Commission stated: "SB 529 does not require an existing electrical transmission facility to be operational for SB 529 to apply. Moreover, SDG&E provides examples in which an extension, expansion, upgrade, or other modification to an existing electrical transmission facility may occur on property under utility control where there is currently no electrical infrastructure located. Therefore, we decline to adopt OIR Attachment A's definition of 'existing electrical transmission facility.' We direct that a definition of "existing electrical transmission facility" be further considered during Phase 2 of this proceeding." (D.23-12-035, December 14, 2023, at 9)

- EDF contends, "In its Phase 1 Decision, the Commission already established that this term is not limited to facilities that are "operational," and that streamlined projects may occur on property under utility control where electrical infrastructure does not yet exist. The Commission further established that an "existing electrical transmission facility" need not be one that was previously "authorized," and that authorization alone would not be sufficient for a facility to be considered existing." (*Comments of Environmental Defense Fund on Phase 2 Issues*, February 5, 2024, at 3)

Staff recommend Proposal 2, Option 1 for the following reasons:

- **A range of parties have expressed support for adopting clear definitions of these terms to ensure consistency in the application of the SB 529 process.** Defining "extension", "expansion", "upgrade", and "modification" would provide clarity to applicants regarding which projects are eligible for the SB 529 process whereby applicants can file a PTC application or claim an exemption for certain projects previously covered by the CPCN requirement. Furthermore, providing clear definitions would help ensure the consistent interpretation of Section III.A by current and future CPUC staff. A range of parties have expressed support for adopting definitions that clearly delineate which types of projects are eligible for the SB 529 process.
  - In its opening comments on the R.23-05-018 OIR, SDG&E asserts, "To avoid confusion about when utilities may use this option, and ensure consistency in how it is applied in future proceedings, SDG&E requests that the Commission provide its interpretation of 'extension, expansion, upgrade, or modification" of an "existing electrical transmission facility."' (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, June 22, 2023, at 34)
  - Cal Advocates asserts, "In Phase 1 of this proceeding, the Commission fulfilled the explicit directive of SB 529, updating GO 131-D to authorize an exemption from a CPCN for the construction of "an extension, expansion, upgrade, or other modification to an electric public utility's existing electrical transmission facilities." Several parties and the bill analysis of SB 529 have noted that the terms "extension," "expansion," "upgrade," and "modification" create ambiguity as to the type of project that would qualify for this exemption. As revised by D.23-12-035, GO 131-D may allow an applicant to file any project involving an existing transmission facility as a PTC regardless of its scale, cost, or relationship to existing infrastructure. In passing SB 529, the Legislature recognized that the

Commission would be responsible for plainly defining the threshold under which projects may utilize the PTC process." (*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruing Inviting Comment on Phase 2 Issues*, February 5, 2024, at 4)

  - The Sierra Club asserts, "Sierra Club's comments have repeatedly highlighted the need to define the terms "extension," "expansion," "upgrade," and "modification."" (*Sierra Club Reply Comments on Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 3)
  - The Acton Town Council states, "To achieve consistency with SB 529 and the legislative intent behind SB 529, the terms "Expansion", "Extension", "Modification", and "Upgrade" must be carefully crafted and expressly limited so that only certain transmission projects are eligible for the PTC permit process in lieu of the CPCN process. The Acton Town Council anticipates that parties in this proceeding will generally agree with this proposition; for instance, San Diego Gas & Electric, Southern California Edison, Large-Scale Solar Association, Independent Energy Producers, The Coalition of California Utility Employees, LS Power Grid California, American Clean Power – California, Environmental Defense Fund, Horizon West Transmission, Trans Bay Cable, and GridLiance West just recently affirmed their understanding that GO 131-D as modified by D.23-12-035 allows utilities to choose the PTC process rather than the CPCN process only "for ***certain*** projects consistent with SB 529" (emphasis added)." (*Opening Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024 at 11)

- **A range of parties support definitions that clearly distinguish the "extension", "expansion", "upgrade", and "modification" of existing facilities from the construction of new facilities.**
  - Cal Advocates asserts, "The Commission should establish definitions that clearly distinguish an "extension, expansion, modification, or upgrade" from a "new electric transmission facility." This distinction would enable reasonable and consistent application of the CPCN exemption and ensure the Commission's review of new large-scale transmission projects that may pose rate concerns." (*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruing Inviting Comment on Phase 2 Issues*, February 5, 2024, at 5)
  - The Sierra Club explains, "The first limitation designed to prevent an overly broad category here is the requirement that an extension start at the "terminus" of an existing line. This means that an extension only qualifies as such if it attaches to the grid at the end point of a line: a project branching off from part-way down a line would correctly be classified as a new line, not an extension. Sierra Club believes this limitation is crucial to avoid widespread circumvention of California's review process. The second limitation is that an extension should not necessitate the addition of new major supportive transmission facilities to support it. This should prevent a transmission developer from finding an existing terminus and building out from there for hundreds of miles to open up service to a large swath of land, without going through the full CPCN review. Insertion of these in-kind limitations enabled Sierra Club to avoid the fraught task of trying to figure out a numeric limitation on the length of extensions, which would be both a challenging and imprecise exercise." (*Sierra Club Opening Comments on Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 5-6)

- The Center for Biological Diversity, Clean Coalition, and POCF assert that the intent of SB 529 was not to allow major projects to escape environmental review: "CEQA strikes a proper balance, ensuring that major projects with significant environmental impacts include adequate notice to the public, a thorough identification of those impacts, and adoption of potential mitigation measures. The Commission's definitions should take this same approach. SB 529 did not intend to allow major projects to skip environmental or cost review. As the author of SB 529 stated clearly, it expedites approvals "least likely to pose rate concerns" for "upgrades to existing transmission system facilities in existing corridors." Nor did the bill intend to allow for major expansion of transmission projects without regard to their potentially significant environmental impacts." (*Center for Biological Diversity, Clean Coalition & the Protect Our Communities Foundation Opening Comments on Phase 2 Issues,* February 5, 2024, at 8-9)
- The Center for Biological Diversity and POCF further assert, "The utilities each take a similar approach to defining terms. PG&E states that the phrase "'extension, expansion, upgrade, or other modification' was intended to capture all types of modifications to existing facilities necessary to reinforce the electric grid and interconnect new energy resources." SDG&E similarly argues that these terms are "intended to capture essentially all transmission projects that are interconnected to the public utilities' existing transmission facilities." SCE provides plain meaning definitions that would achieve similar results to SDG&E and PG&E's; any project would be covered so long as it results in "longer, larger or additional facilities or right-of-way," "additional or longer over-200 kV lines to connect to a new or different substation, generation source, or large end user," "a change to, or alteration of, existing transmission line structures, conductors, substation equipment that results in a voltage increase, a power transfer increase, or both," or "a change to, or alteration of, existing structures, conductors, and/or other transmission facilities, whether or not also constituting an expansion, extension, or upgrade." The problem with these definitions is obvious: they would encapsulate virtually every transmission project." (*Center for Biological Diversity and Protect Our Communities Foundation Reply Comments on Phase 2 Issues,* February 26, 2024, at 2)

- **A range of parties support the adoption of overlapping definitions of "extension", "expansion", "upgrade", and "modification", including a broad definition of "modification" that may include examples provided for the other three categories.**
  - EDF asserts, "The Commission should avoid proposals to adopt more narrow definitions of these and other terms that would make SB 529's streamlining efforts meaningless. For example, when the Legislature adopted SB 529, GO131-D already excluded minor projects from the requirement to obtain a Certificate of Public Convenience and Necessity (CPCN). Namely, under Section III.A, a CPCN is not required for "the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing power line facilities, the conversion of existing overhead lines to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built." Because the Legislature was aware

that these projects were already excluded from a CPCN requirement, SB 529's terms must be defined to apply to a broader set of projects to give them meaning." (*Comments of Environmental Defense Fund on Phase 2 Issues*, February 5, 2024, at 7-8)

- In its comments on the ALJs' Ruling Inviting Phase 2 Issues, SDG&E states, "While recognizing that the terms are overlapping, SDG&E understands the utility of adopting definitions that provide clarity and avoid future confusion." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 5, 2024, at 10)
- In its comments on the R.23-05-018 OIR, SDG&E states, "While to some extent these definitions are overlapping, the Legislature clearly meant to broadly capture transmission projects by a "public utility electric corporation" to provide service to its customers, whether it is an extension of the existing electric grid, an expansion in capacity, an upgrade of existing facilities or a modification of existing facilities to better serve customers." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, June 22, 2023, at 34)
- PG&E explains, "An "expansion" is an increase. For this reason, its definition overlaps with "extension," "upgrade" and "other modification" in Section III.A's new paragraph." (*Opening Comments of the Pacific Gas and Electric Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 5) PG&E further asserts, "As the words "or other modifications" suggest, all extensions, expansions and upgrades are also "modifications," but the phrase was clearly added to capture any transmission facility work involving existing transmission facilities that might not have qualified under the other definitions. Again, there is considerable overlap in these definitions". (*Opening Comments of the Pacific Gas and Electric Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 7)

- **The criteria and examples used in the proposed definitions of "extension", "expansion", "upgrade", and "modification" are supported by party comments.** In developing the proposed definitions of "extension", "expansion", "upgrade", and "modification", CPUC staff carefully reviewed the extensive party comments provided in response to the ALJs' Ruling Inviting Comment on Phase 2 Issues in order to establish definitions that are supported by the proceeding record. Key themes from the party comments are summarized in the bullet points below.
- **The party comments support a definition of "extension" that involves lengthening existing electrical transmission facilities to connect to or extend from existing infrastructure.** Comments submitted by a range of parties (Acton Town Council, the Center for Biological Diversity, Clean Coalition, POCF, EDF, Cal Advocates, PG&E, SCE, SDG&E, Sierra Club) support an interpretation of "extension" that involves lengthening existing electrical transmission facilities to connect to or extend from existing infrastructure.
    - EDF suggests the following definition of "extension": "A section or line segment forming an additional length, i.e., constructing a new segment of transmission line that connects to the terminus of an existing transmission line, and does not include the construction of an additional substation or transformer." (*Comments of Environmental Defense Fund on Phase 2 Issues,* February 5, 2024, at 6)

- PG&E suggests the following definition of "extension": "Transmission line construction that extends existing over-200 kV lines to a new or different substation, generating source (solar, wind), or large load (data center)." (*Opening Comments of Pacific Gas and Electric Company (U 39-E) on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 3)
- SCE suggests the following definition of "extension": "Major transmission line construction that results in additional or longer over-200 kV lines to connect to a new or different substation, generation source or large end user." (*Southern California Edison Company's (U 338-E) Opening Comments on the Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 6)
- SDG&E suggests the following definition of "extension": "An "extension" to existing electrical transmission facilities is a new facility interconnected to existing electrical transmission facilities." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues,* February 5, at 13)
- The Sierra Club suggests the following definition of "extension": "Constructing a new segment of transmission line that connects to the terminus of an existing transmission line, and does not include the construction of an additional substation or transformer." (*Sierra Club Opening Comments on Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 5)

- **The party comments support a definition of "extension" that is limited to extensions of existing electrical transmission facilities within existing easements, rights of way, or franchise agreements.** A range of party comments support a definition of "extension" that is limited to extensions within existing easements, rights of way, or franchise agreements.
  - The Center for Biological Diversity, Clean Coalition, and POCF suggest the following definition of "extension": "The policy-driven construction, within an existing easement, right of way, or franchise agreement, of an electric transmission or power line facility that connects an existing electric transmission facility to a service delivery point and does not have a significant effect on the environment or rates." (*Center for Biological Diversity, Clean Coalition & The Protect Our Communities Foundation Opening Comments on Phase 2 Issues,* February 5, 2024, at 10)
  - The Acton Town Council suggests the following definition of "extension": "The lengthening or broadening of an existing structure within an existing developed footprint of an existing transmission facility." (*Opening Comments of the Action Town Council on the Administrative Law Judes'Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 12)
- **The party comments support a definition of "expansion" that includes increasing the width, capacity, or capability of an existing electrical transmission facility.**
  - The Center for Biological Diversity, Clean Coalition, and POCF suggest the following definition of "expansion": "'Expansion' (as used in Section 564 and Section III.A of GO 131-D) should be defined as 'policy-driven construction, within an existing easement, right of way, or franchise agreement, that adds new facilities or capacity to an existing electric transmission facility and does not have a significant effect on the environment or rates.'" (*Center for Biological Diversity, Clean Coalition & The Protect Our Communities Foundation Opening Comments on Phase 2 Issues,* February 5, 2024, at 10)

  - SDG&E suggests the following definition of "expansion": "An 'expansion' to existing electrical transmission facilities increases the size, capacity or capability of existing transmission facilities." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues,* February 5, at 13)
  - SCE suggests the following definition of "expansion": "'Expansion' is an increase in size or a project that results in longer, larger or additional facilities or right-of-way." (*Southern California Edison company's (U 338-E) Opening Comments on the ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 6)
  - The Sierra Club suggests the following definition of "expansion": "Increasing the carrying or processing capacity of existing electric transmission facilities." (*Sierra Club Opening Comments on Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 6)
- **The party comments support a definition of "upgrade" that includes replacing or altering existing facilities to enhance the rating, voltage, capacity, capability, or quality.**
  - The Acton Town Council suggests the following definition of "upgrade": "Altering existing transmission equipment to increase its capacity without enlarging the developed footprint of the equipment or increasing its operating voltage." (*Opening Comments of the Action Town Council on the Administrative Law Judes'Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 14)
  - The Center for Biological Diversity, Clean Coalition, and POCF suggest the following definition of "upgrade": "'Upgrade' (as used in Section 564 and Section III.A of GO 131-D) should be defined as 'policy-driven construction that improves an existing electric transmission facility and does not have a significant effect on the environment or rates.'" (*Center for Biological Diversity, Clean Coalition & The Protect Our Communities Foundation Opening Comments on Phase 2 Issues,* February 5, 2024, at 10)
  - SCE suggests the following definition of "upgrade": "A change to, or alteration of, existing transmission line structures, conductors, substation equipment, and/or other facilities that results in a voltage increase, a power transfer increase, or both." (*Southern California Edison company's (U 338-E) Opening Comments on the ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 7)
  - SDG&E suggests the following definition of "upgrade": "An 'upgrade' to existing electrical transmission facilities improves the quality or usefulness of existing transmission facilities." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues,* February 5, at 13)
  - The Sierra Club and EDF both suggests the following definition of "upgrade": "Replacing existing electric transmission facilities with more useful or modern versions of those same facilities." (*Sierra Club Opening Comments on Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024, at 6; *Comments of Environmental Defense Fund on Phase 2 Issues,* February 4, 2024, at 7)

Staff recommend Proposal 3 for the following reasons:

- **Defining "equivalent facilities or structures" could clarify the applicability of the CPCN and PTC exemptions in GO 131-D Sections III.A and III.B.** Although the term "equivalent facilities or structures" is used to define which projects do not require issuance of a CPCN (in Section III.A) or a PTC (in Section III.B.1.b), the term is not defined in the current version of GO 131-D. Defining the term could support a streamlined application process by making it easier for applicants to interpret whether a particular project qualifies for a CPCN, a PTC, or an exemption.

  - The Center for Biological Diversity, Clean Coalition, and POCF state, "Equivalent facilities or structures" (as used in the phrase "the replacement of existing power line facilities or supporting structures with equivalent facilities or structures" in Sections III.A and III.B.1.b of GO 131-D) […] should be defined to ensure that the facility, structure, or accessory construction does not have a significant effect on the environment or rates." (*Center for Biological Diversity, Clean Coalition & the Protect Our Communities Foundation Opening Comments on Phase 2 Issues,* February 5, 2024, at 10-11)
  - PG&E and SDG&E assert that there is no need for the CPUC to adopt a definition for "equivalent facilities or structures" (*Opening Comments of the Pacific Gas and Electric Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 7; *Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 5, 2024, at 13). However, other parties, such as the Acton Town Council, argue that defining this term is appropriate provided that the "equivalence" is limited (e.g., no increase in voltage). (*Opening Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 14)

- **Party comments support a flexible definition of "equivalent facilities or structures".**
  - PG&E states, "The Commission has defined "replacement" with "equivalent facilities or structures" as being equivalent in "function and purpose" to the facilities being replaced. … If a definition of "equivalent facilities or structures" must be adopted for this long-standing exemption (and PG&E asserts that is not the case), PG&E recommends that "equivalent" continue to be flexibly defined as equivalent in function and purpose." (*Opening Comments of the Pacific Gas and Electric Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 7-8)
  - SDG&E advocates for a broad interpretation of "equivalent facilities or structures" which may be dependent on the circumstances: "SDG&E understands "equivalent facilities or structures" to mean replacing structures or equipment due to age, safety, or risk of failure concerns, which may require changing their number, location and design, depending on the circumstances, and including SDG&E's current design and equipment standards and applicable building codes." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 5, 2024, at 13-14)

- **A range of parties support limiting "equivalent facilities or structures" to those with no greater voltage than the facilities or structures being replaced.**
  - SCE asserts that equivalent power transfer capability (i.e., voltage) is an appropriate criterion for replacement facilities or structures to be considered "equivalent": "Facilities and supporting structures providing power transfer capability at no greater voltage than the structure or facility to be replaced. The type of material, relative size or type of the structure is not determinative of whether the new facility or structure is "equivalent" to the structure

or facility to be replaced." (*Opening Comments of the Southern California Edison Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 9-10)

- The Acton Town Council asserts that rating and capacity are appropriate criteria for replacement facilities or structures to be considered "equivalent": "The term "Equivalent Facilities or Structures" means: New facilities and structures that are the same as the existing facilities and structures which they replace in terms of materials, configuration, size, rating, and capacity." (*Opening Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues,* February 5, 2024 at 14)

Staff recommend Proposal 4 for the following reasons:

- **Defining "accessories" could clarify the applicability of the CPCN and PTC exemptions in GO 131-D Sections III.A and III.B.** Although the term "accessories" is used to define which projects do not require issuance of a CPCN (in Section III.A) or a PTC (in Section III.B.1.e), the term is not defined in the current version of GO 131-D. Defining the term could support a streamlined application process by making it easier for applicants to interpret whether a particular project qualifies for a CPCN, a PTC, or an exemption.
    - The Center for Biological Diversity, Clean Coalition, and POCF assert, "'Accessories' (as used in the phrase "the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built" in Section III.A and similar phrases in Sections III.B.1.e and VI of GO 131-D) should be defined to ensure that the facility, structure, or accessory construction does not have a significant effect on the environment or rates." (*Center for Biological Diversity, Clean Coalition & The Protect Our Communities Foundation Opening Comments on Phase 2 Issues,* February 5, 2024, at 11)
- **A range of parties expressed support for a definition that references the safe and reliable operation of the transmission system.**
    - The Acton Town Council asserts, ""Accessories" means: equipment that is located at an electrical substation or attached to an electrical power line facility which does not deliver or transmit electrical power but is essential for proper operation of the electrical substation or electrical powerline facility." *(Opening Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 15)
    - SCE proposes the definition, "Equipment and hardware used for the structural support of, and/or safe and reliable operation of, power line facilities (such as conductors, switches, telecommunications equipment, insulators, and/or other appurtenances)." (*Opening Comments of the Southern California Edison Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 10)
    - SDG&E asserts, "SDG&E understands 'accessories' to mean individual transmission line or substation equipment such as connectors, relays, control shelters, and other facilities required for the safe and reliable functioning of the transmission system." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 5, 2024, at 14)
- **The party comments support a broad definition of "accessories".**

- PG&E asserts, "PG&E urges the Commission not to restrict the use of these exemptions by adopting less-expansive definitions. … 'Accessories' has also been defined flexibly in practice, consistent with its plain meaning to be something added to something else to make it more useful." (*Opening Comments of the Pacific Gas and Electric Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 7-8)
- SCE and SDG&E both propose a range of equipment and hardware that could qualify as "accessories". The lists of "accessories" provided by SCE and SDG&E only partially overlap, supporting a broad, minimally restrictive interpretation. (*Opening Comments of the Southern California Edison Company on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 10; *Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 5, 2024, at 14)

Staff recommend Proposal 5, Option 1 for the following reasons:

- **The settling parties support adding "right-of-way" to the first exemption "g" category before the semicolon.** In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties assert, "Most utility ROW is pursuant to an easement, but it is the fact that it is a utility right of way that is important, not the legal instrument creating the ROW. How the utility came to possess that property is immaterial; the key point is that given the presence of an existing ROW, new facilities are less likely to lead to significant impacts in such locations compared to non-utility areas." (*Joint Motion for Adoption of Phase 1 Settlement Agreement*, September 29, 2023, at 49)
- **The settling parties support amending Section III.B.1.g to add "power lines or substations" to the second exemption "g" category after the semicolon.** In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by PG&E, SCE, and SDG&E on September 29, 2023, the settling parties assert, "Additional revisions are also recommended to confirm that this exemption sub-paragraph contains two separate and independent provisions […] By adding the phrase, 'power line facilities or substations' to the second prong, which is set off from the first clause by a semi-colon, the Commission would correct a grammatical mistake. […] the Settling Parties propose to add 'power line facilities or substations' to the second clause simply to clarify that, despite the semi-colon separating the first clause from the second clause, the exception still applies to 'power line facilities or substations.'" (*Joint Motion for Adoption of Phase 1 Settlement Agreement*, September 29, 2023, at 48-49)
- **The settling parties support amending Section III.B.1.g to explicitly reference MNDs (in addition to EIRs and NDs).** In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties assert, "Third, the existing exception exempts power line facilities or substations in certain utility corridors for which "a final Negative Declaration or EIR finds no significant unavoidable environmental impacts." The Settling Parties propose to clarify that this prong of the exception also applies to such finding in a Mitigated Negative Declaration." (*Joint Motion for Adoption of Phase 1 Settlement Agreement*, September 29, 2023, at 48-49)

Staff recommend Proposal 6, Option 1 for the following reasons:

- **A range of parties expressed opposition to fully deleting exemption "h".** As discussed in the Decision Addressing Phase 1 Issues (D.23-12-035) (pages 10-11), OIR Attachment A proposed to delete the exemption found in Section III.B.1.h for projects that are statutorily or categorically exempt from CEQA, as well as the notice exception for these projects. However, parties including PG&E, SCE, SDG&E, CUE, American Clean Power, LS Power, Large Scale Solar Association, and RCRC expressed opposition to the proposed deletion of Section III.B.1.h. These parties argued that the proposed deletion was not justified, was not required by SB 529, and would conflict with the legislative intent of SB 529 to accelerate the review of upgrades to existing transmission facilities. In response, D.23-12-035 deferred consideration of the deletion of Section III.B.1.h and notice exception to Phase 2. In acknowledgement of the party input received in Phase 1, none of the three options set forth in Proposal 6 involve the deletion of Section III.B.1.h. Instead, Option 1 seeks to establish a process for utilities to provide notice of exempt projects without delaying the review of upgrades to existing transmission facilities.
    - In its opening comments on the R.23-05-018 OIR, CUE stated, "Attachment B would also, for example, eliminate GO 131-D's "Exemption h" which exempts a project from the Commission's PTC process if the project is statutorily or categorically exempt under CEQA. This proposed revision would subject a project to the Commission's PTC process even though the project has been determined to not have significant environmental impacts. This is contrary to the intent of SB 529 and the Commission's own reasoning when it adopted GO 131-D and stated, "the sole purpose of the permit to construct is to ensure that environmental considerations have been fully taken into account" and, therefore, "there is no need for the utility to apply for a permit to construct when the activity falls within categories the Legislature or the Resources Agency has determined will not result in significant environmental effects." (*Opening Comments of the Coalition of California Utility Employees on Order Instituting Rulemaking*, June 22, 2023, at 6)
    - In its opening comments on the R.23-05-018 OIR, the Large-Scale Solar Association stated, "Attachment B would remove PTC exemptions for projects with low environmental hurdles … These changes may remove some perceived ambiguity and increase oversight for CPUC staff, but they would also remove existing pathways for expedited treatment and increase opportunities for protest and delay, which would move the permitting process in the opposite direction from the intent of SB 529." (*Opening Comments of the Large-Scale Solar Association on the Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, June 22, 2023, at 3-4)
- **As written, exemption "h" could enable utilities to independently determine that a project is statutorily or categorically exempt from CEQA, which would be inconsistent with the CEQA Guidelines.** As written, Section III.B.1.h and the final paragraph of Section III.B.1 could foreseeably enable a utility to independently determine that an activity meets the criteria for a statutory or categorical exemption, then construct the project without providing notice of the proposed construction, which would be inconsistent with CEQA. Section 15061 of the CEQA Guidelines clearly establishes that the lead agency is responsible for determining whether a project is exempt from CEQA, stating: "Once a lead agency has determined that an activity is a project subject

to CEQA, a lead agency shall determine whether the project is exempt from CEQA." Section 15062(a) goes on to state, "When a public agency decides that a project is exempt from CEQA pursuant to Section 15061, and the public agency approves or determines to carry out the project, the agency may file a Notice of Exemption."

- **Requiring notice of exemption "h" projects via an information-only submittal would ensure that utilities provide notice of such projects while minimizing the additional administrative burden for utilities and Commission staff.** Requiring notice of projects that are categorically or statutorily exempt from CEQA via an information-only submittal (rather than via a Tier 2 advice letter, as is the case for other GO 131-D advice letters) would ensure that Commission staff have the opportunity to review and "determine whether the project is exempt from CEQA" pursuant to Section 15061 of the CEQA Guidelines while minimizing the associated workload for Commission staff and utilities.
  - Unlike advice letters and applications, information-only submittals are not subject to protest because they do not seek relief. However, GO 96-B General Rule 6.2 establishes a process whereby Energy Division staff could request correction of any omissions or defects in the submittal, which could include an erroneous assertion that a given activity is exempt from CEQA—effectively providing staff with an avenue to comply with CEQA Guidelines Section 15061. GO 96-B General Rule 6.2 states: "The reviewing Industry Division may notify the utility of any omission or other defect in a submittal, and the utility shall remedy such defect within a reasonable time. A utility that fails to remedy defects or fails to submit a required report on time or at all shall be subject to fines and other sanctions."

3.2 Update Reporting Requirements

3.2.1 Problem Statement

GO 131-D Sections IV, V, and VI outline an array of reporting requirements for electric public utilities. These reporting requirements are as follows:

- **Pursuant to Section IV**, every electric public utility that is required to submit a report of loads and resources to the California Energy Commission (CEC) in accordance with Section 25300 et seq. of the Public Resources Code must also submit an electronic copy of its report to the CPUC.
- **Pursuant to Section V,** every electric public utility must submit an annual report to the CPUC Energy Division by March 1 of each year comprising a fifteen-year forecast of planned transmission

facilities of 200 kV or greater and a five-year forecast of planned power line facilities and substations between 50 kV and 200 kV.[9]

- **Pursuant to Section VI**, every electric public utility must submit a biennial report on or before June 1 of every odd-numbered year containing the financial information designated in Appendix A of GO 131-D, including but not limited to anticipated construction expenditures, operating costs, revenues and income, capital requirements, and results of operation.[10]

Since 1994, when GO 131-D was first adopted, additional reporting processes have emerged that are not referenced in the general order. Specifically, this section will address the Transmission Project Review Process (TPR Process) and the Commission's practice of holding quarterly meetings with public utilities to review each utility's active and forecasted transmission projects.

The TPR Process is a semi-annual reporting process that requires California's investor-owned utilities (IOUs)—PG&E, SCE, and SDG&E—to provide the CPUC and stakeholders with cost data for all past, current, and forecasted capital transmission projects expected to total $1 million or more in capital costs. The CPUC established the TPR Process effective January 1, 2024 with the passage of Resolution E-5252 on April 27, 2023. The TPR Process integrated requirements from three separate reporting processes—PG&E's Stakeholder Transmission Asset Review ("STAR") Process, SCE's Stakeholder Review Process ("SRP"), and SDG&E's Evaluation of Forecast Period Capital Additions ("Project Evaluation")—all of which were replaced by the TPR Process at the end of 2023.

Pursuant to Resolution E-5252, the TPR Process requires the three IOUs to provide "current, specific, comprehensive, and system-wide transmission data for projects with capital additions to rate base in the last five years and forecasted or actual capital expenditures in the current year and future four years" including "specific projects, as well as programmatic buckets or blanket program categories (collectively "Projects"), that are CAISO-approved or Utility Self-Approved, as well as transmission network upgrades needed for generator interconnections". The IOUs must also provide the CPUC and all stakeholders with their "current asset management procedure documents relied on for identifying, proposing, authorizing, planning, prioritizing, budgeting, and executing Projects". Although overlap exists between the information required in GO 131-D Sections V and VI and the information provided via the TPR Process, GO 131-D and the TPR Process serve distinct functions. The TPR Process, while a requirement pursuant to Resolution E-5252, is acknowledged as a stakeholder process in which the CPUC can scrutinize, but does not have

[9] Typical annual reports submitted pursuant to Section V contain project information including the project name and description, planned operating date, project type, filing type (e.g., CPCN, PTC), number of circuits, voltage, normal and emergency rating, line length, estimated cost, local jurisdiction(s), and utility comments.

[10] Utilities are not required to submit biennial reports pursuant to Section VI if they do not plan, within the next 15 years, to conduct any of the following activities: 1) construct new electric generating plans with net capacity in access of 50 MW; 2) modify, alter, or add to an existing electric generating plant resulting in an increase of 50 MW or more to the electric generating capacity; or 3) construct electric transmission facilities designed to operate at voltages in excess of 200 kV (except for the replacement or minor relocation of existing transmission line facilities, or the placing of additional conductors, insulators, or their accessories on, or replacement of, supporting structures already built).

binding authority over, the costs and recovery of costs for FERC jurisdictional assets. In contrast, the CPUC has binding authority as the regulator in GO 131-D.

In the years since 1995, CPUC Energy Division staff have developed a de facto reporting process wherein staff participate in quarterly briefings organized by each of the large IOUs. In these briefings, which are generally scheduled to last between one and two hours, the utilities present a summary of active and upcoming transmission projects subject to CPUC permitting, including projects identified in CAISO transmission plans. The information presented for each project typically includes the project name and description, purpose and need, filing type, status, actual or expected filing date, actual and projected cost (total and per year), CAISO transmission plan year(s) (if applicable), and expected in-service date. Prior to or shortly after each briefing, the IOU typically shares a PDF of the presentation with Energy Division staff. Although the quarterly briefings constitute a well-established practice, there is no mention of them in GO 131-D. Updating GO 131-D to reference the existing practice of quarterly briefings with electric public utilities would codify the practice and clarify how it relates to the other reporting requirements outlined in the General Order.

The proposals in this section would modify Sections V and VI and Appendix A of GO 131-D to better reflect these existing reporting practices.

3.2.2 Proposals

Proposal 1: Update Section V to Reference Existing Practice of Quarterly Briefings

This proposal would update Section V of GO 131-D to reference the existing practice of quarterly meetings between CPUC Energy Division staff and electric public utilities wherein the utilities present a forecast of planned transmission facilities, power line facilities, and substations. Specifically, this proposal would modify Section V to specify that in addition to providing the report on an annual basis as required by the current version of GO 131-D, the utilities shall organize a quarterly briefing with the Energy Division to present the working version of the forecast. The revised text of Section V would detail that information that utilities must provide in such a briefing, including a forecast of planned facilities and forthcoming applications, and a summary of projects that have been reprioritized since the last quarterly briefing.

The revised text of Section V would read as follows:

A. Every electric public utility shall annually, on or before March 1, ~~furnish~~ submit to the Commission's Energy Division (Energy Division) an electronic copy of a ~~fifteen-year (15) forecast of~~ report on planned transmission facilities ~~of 200 kV or greater~~ and ~~a five-year (5) forecast of~~ planned power line facilities and substations ~~of between 50 kV and 200 kV~~.

B. The annual report shall include:

1. A fifteen (15) year forecast of planned transmission facilities of 200 kV or greater and a five-year (5) forecast of planned power line facilities and substations of between 50 kV and 200 kV.
2. A list of transmission, power lines, and substations, arranged in chronological order by the planned service date, for which a CPCN or a ~~permit to construct~~ PTC has been received, but which have not yet been placed in service.
3. A list of planned transmission, power lines, and substations of 50 kV or greater or planning corridors, arranged in chronological order by the planned service date, on which proposed route or corridor reviews are being undertaken with governmental agencies or for which applications have already been filed.
4. A list of planned transmission, power lines, and substations of 50 kV or greater or planning corridors, arranged in chronological order by the planned service date, on which planning corridor or route reviews have not started, which will be needed during the forecast periods.
5. For each transmission or power line route, substation, or planning corridor included in the above lists, the following information, if available, shall be included in the report:
   - Planned operating date.
   - Transmission or power line name.
   - The terminal points (substation name and location).
   - Number of circuits.
   - Voltage – kV.
   - Normal and emergency continuous operating ratings – MVA.
   - Length in feet or miles.
   - Estimated cost in dollars as of the year the report is filed.
   - Cities and counties involved.
   - Other comments.

C. Additionally, on a quarterly basis, every electric public utility shall organize a meeting with the Energy Division, unless Energy Division staff confirm in writing that such a meeting is not needed, wherein the utility will present a briefing that includes the following:

   1. The latest version of the forecast of planned transmission line, power line, and substation facilities required herein;
   2. A forecast of any CPCN or PTC applications expected to be submitted within the following two years;
   3. Estimated application filing dates for all CAISO-approved transmission plan projects; and
   4. A summary of any projects that have been reprioritized since the last quarterly briefing.

Staff recommend adoption of this proposal. The rationale for the staff recommendation is provided in Section 3.2.4 below.

Proposal 2: Update Appendix A to Require Provision of Capital Costs and Other Financial Information

This proposal would modify Appendix A of GO 131-D (as proposed in Attachment B to the OIR) to include additional items to the list of financial information that electric public utilities must provide to the CPUC in biennial reports pursuant to Section VI. This additional financial information is already provided to some extent in the TPR Process, which the Section VI reports predate and supplement. The proposed changes to Appendix A of GO 131-D are detailed in Appendices A and B of this staff proposal and summarized below.

First, this proposal would modify the title of GO 131-D Appendix A to include "power line" projects, such that the title would read: "Information to be Included in the Utility Report Regarding Financing of New Electric Generating Capacity, Transmission Line, and Power Line Projects".

Second, this proposal would add a new Section I.B and I.C to GO 131-D Appendix A requiring provision of the following information in the categories of "Capital Costs Added to Rate Base" and "Long-Term Capital Costs":

B. Capital Costs to be Added to Rate Base
- 1. Direct Material Costs
- 2. Direct Labor Costs
- 3. Allowance for Funds Used During Construction (AFUDC) accrued
- 4. Construction Work in Progress (CWIP) added to rate base due to incentive
- 5. Overhead
- 6. Others

C. Long-Term Capital Costs
- 1. Rate of Return
  - Return on Equity (ROE) (common stock)
  - Return on Preferred Stock
  - Long-Term Debt
- 2. Depreciation
- 3. Taxes on ROE

Finally, this proposal would make the following additional modifications to GO 131-D Appendix A. All sections referenced in the bullet points below are sections of GO 131-D Appendix A.

- Modify current Section I.B of Appendix A to be Section I.D, and rename that section from "Operating Expenses" to "Operating and Maintenance (O&M) and Administrative and General (A&G) Expenses and Taxes"
- Modify the subsequent subsections following current section I.B of Appendix A to be sections I.E through I.N, in order to accommodate the insertion of the new Section I.B (Capital Costs Added to Rate Base) and Section I.C (Long-Term Capital Costs)

- Modify the fifth item listed in current Section I.B of Appendix A, Operating Expenses (as modified, Section I.D), from “Depreciation” to “Insurance”
- Strike the first item listed in current Section I.D of Appendix A, Other Income and Deductions (as modified, Section I.F), “Allowance for Equity Funds Used During Construction”, and adjust the remaining item numbers accordingly
- Modify Section II.A of Appendix A to include materials, labor, overhead, and AFUDC in the list of construction expenditures that must be reported, as follows: “Construction expenditures by year, including materials, labor, overhead, and AFUDC, broken down by:”

Staff recommend adoption of this proposal. The rationale for the staff recommendation is provided in Section 3.2.4 below.

3.2.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1: Staff recommend adoption of Proposal 1. The rationale for the staff recommendation is provided in Section 3.2.4 below.

Proposal 2: Staff recommend adoption of Proposal 2. The rationale for the staff recommendation is provided in Section 3.2.4 below.

3.2.4 Rationale for Staff Recommendations

Staff recommend Proposal 1 for the following reasons:

- **Adding the quarterly briefings to Section V would update the GO 131-D reporting requirements to better reflect existing practices.** Although the quarterly briefings between Energy Division staff and electric public utilities have become a well-established practice, there is no mention of them in GO 131-D. Updating Section V of GO 131-D to reference the existing practice of quarterly briefings with electric public utilities would codify the practice and clarify how it relates to the other reporting requirements outlined in the General Order.
    - In its response to R.23-05-018 Data Request 01, Question 2c, PG&E stated, “Currently, PG&E already provides project information to the CPUC in advance of pre-filing, in quarterly and monthly meetings, and in regularly submitted reports, including the Stakeholder Transmission Asset Review (STAR) Process, CAISO Transmission Development Forum (TDF), and Assembly Bill (AB) 970 reports.” (*Pacific Gas and Electric Company GO 131-D Update and Amend OIR Rulemaking 23-05-018 Data Response* [Question 2], March 8, 2024, at 2) PG&E goes on to explain that the quarterly meetings are “attended by PG&E Asset Strategy and Environmental Management teams, CPUC Energy Division” and that the information provided includes high-level information on project need, project route, project status, permit filing status, and projected annual and total spend for in-flight and

> projected filings." (*Pacific Gas and Electric Company GO 131-D Update and Amend OIR Rulemaking 23-05-018 Data Response* [Question 2], March 8, 2024, at 3)

Staff recommend Proposal 2 for the following reasons:

- **GO 131-D and the TPR Process serve distinct functions, so the reporting requirements in GO 131-D are additive, not duplicative.** The TPR Process, while a requirement pursuant to Resolution E-5252, is acknowledged as a stakeholder process in which the CPUC can scrutinize, but does not have binding authority over the costs and recovery of costs for FERC jurisdictional assets. In contrast, the CPUC has binding authority as the regulator in GO 131-D. While there may be overlap between the information required in the GO 131-D Section V and VI reports and the information provided via the TPR Process, the GO 131-D requirements cannot be fully replaced by a non-binding stakeholder process. Updating GO 131-D Appendix A to include additional information provided in the TPR Process is intended to ensure that a binding requirement to provide said information exists in the General Order.
- **The Commission has recognized that utility transparency regarding planned transmission projects is critical to support the expansion of the transmission grid.** In Resolution E-5252, the Commission explained, "Most utility transmission projects are currently self-approved projects, which lack transparency of their planning, prioritization, budgeting, and implementation. With the anticipation of the aforementioned large expansion of the transmission grid, it is more important than ever that transparency of transmission projects occur to protect ratepayers, ensure the Commission has the ability to track how projects best meet needs related to interconnection of renewable energy resources, CPUC permitting processes, risk and safety assessments, and more broadly address the integrated resource planning needed to meet the state's clean energy goals and the changing electric grid." (Resolution E-5252, April 27, 2023, at 3; available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K896/507896441.PDF).

3.3 Establish Rebuttable Presumption in Favor of CAISO Transmission Plan

3.3.1 Problem Statement

The CPUC reviews CPCN applications under two parallel processes: an environmental review pursuant to CEQA, and a review of project need and costs pursuant to Public Utilities Code sections 1001 et seq. and Sections III.A and IX.A of GO 131-D. As discussed in the Introduction of this staff proposal, the PTC process does not entail a detailed review of project need and cost except as required by the CEQA process.

Public Utilities Code Section 1002.3 requires the CPUC to consider cost-effective alternatives to transmission facilities when considering CPCN applications:

> In considering an application for a certificate for an electric transmission facility…, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, … and other demand reduction resources.

Public Utilities Code Section 1005.5(a) furthermore requires the CPUC to establish a maximum reasonable and prudent cost when issuing CPCNs for projects estimated to cost more than $50 million:

> Whenever the commission issues to an electrical … corporation a certificate authorizing the new construction of any addition to or extension of the corporation's plant estimated to cost greater than fifty million dollars ($50,000,000), the commission shall specify in the certificate a maximum cost determined to be reasonable and prudent for the facility.

Many of the projects submitted for CPUC review in CPCN and PTC applications are electrical transmission projects that have been identified by the California Independent System Operator (CAISO)—the non-profit that manages the flow of electricity for much of California's bulk electric power grid, oversees grid planning, and operates a wholesale energy market—in one or more of its annual transmission plans. In its annual transmission planning process (TPP), the CAISO identifies necessary transmission facilities to meet objectives within three primary categories of transmission solutions: reliability (i.e., to connect energy resources with forecast load in accordance with FERC-approved mandatory North American Electric Reliability Corporation (NERC) criteria), policy requirements (as outlined in FERC Order 1000.58), and economic needs. In many years, the CAISO assigns a subset of the approved transmission facilities to specific developers through a competitive solicitation process. The selected developer for a given project will be the entity to build and own those new transmission facilities.

As part of the transmission planning process, the CAISO assesses the purpose, need, and expected cost of each approved transmission project. Each annual transmission plan includes an explanation of the reasons why each project has been deemed necessary—i.e., reliability, policy requirements, or economic needs—and an estimated cost range for each project. Assembly Bill (AB) 1373 (Garcia, 2023) established a "rebuttable presumption" that once the CAISO deems a transmission project necessary via the TPP, the CPUC should accept the CAISO's determination of need.

In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by PG&E, SCE, and SDG&E on behalf of settling parties on September 29, 2023, the settling parties describe the coordination that occurs between the CPUC, the CEC, and the CAISO throughout the CAISO's transmission planning process, asserting that the CPUC is deeply involved in the development of CAISO TPP findings.

> Transmission planning in California has changed substantially since GO 131-D was adopted in 1994. Today, the Commission, the CEC and the CAISO coordinate on electric load forecasting, resource planning and transmission planning to achieve state reliability and policy goals. The "CAISO utilizes resource portfolios from the Commission's Integrated Resource Plan (IRP) proceeding in order to identify needed transmission projects." As recognized in a December 2022 Memorandum of Understanding among the Commission, the CEC and CAISO, the CAISO conducts electric

> transmission planning to meet the electricity transmission needs for the loads and resources identified by the Commission in response to the CEC's electric load forecasts. The Commission is deeply involved in the CAISO's transmission planning process. (*Joint Motion for Adoption of Phase 1 Settlement Agreement*, September 29, 2023, at 28-29)

In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties outline a set of proposed revisions to GO 131-D, including the creation of a new Section IX.C.2 and IX.C.3, with the stated intention to more explicitly recognize and defer to the CAISO's transmission plan findings.

> In proposed Section IX.C.2, the Settling Parties propose GO 131-D revisions that recognize the extensive transmission system planning work performed by CAISO, in coordination with this Commission, the CEC and interested parties. These provisions would recognize the CAISO's findings regarding a proposed project in a CAISO Governing Board approved Transmission Plan in the Commission's identification of the CEQA statement of objectives, range of reasonable alternatives, and any statement of overriding considerations. The proposed revisions also would establish a rebuttable presumption that the Commission's assessment of preferred resources under Public Utilities Code § 1002.3, if applicable to an application, be limited to such analysis in the CAISO Transmission Plan and the underlying Commission's base resource portfolio for such Plan. Finally, the proposed revision would establish a rebuttable presumption that CAISO approval establishes that the public convenience and necessity require project approval. (*Joint Motion for Adoption of Phase 1 Settlement Agreement*, September 29, 2023, at 28-29)

The CAISO and the CPUC have distinct and separate mandates to consider alternatives to transmission solutions. The role and process of the CPUC in considering proposed transmission projects differs from that of the CAISO in several key ways, not least that the CPUC is a public agency with discretionary powers and an obligation to both comply with CEQA and ensure that public utility infrastructure projects serve the public convenience and necessity pursuant to Public Utilities Code Sections 1001 et seq. Although the CAISO transmission planning process incorporates stakeholder input in the form of comments from market participants, electric utility regulatory agencies, and other interested parties, the CAISO is a non-governmental non-profit entity and does not conduct land use planning or environmental review pursuant to CEQA when studying potential transmission solutions.

Section 15357 of the CEQA Guidelines defines a "discretionary project" as one "which requires the exercise of judgment or deliberation when the public agency or body decides to approve or disapprove a particular activity". Section 15040 of the CEQA Guidelines states that CEQA supplements an agency's discretionary powers "by authorizing the agency to use the discretionary powers to mitigate or avoid significant effects on the environment when it is feasible to do so with respect to projects subject to the powers of the agency." Additionally, Section 15352(b) of the CEQA Guidelines states, "With private projects, approval occurs upon the earliest commitment to issue or the issuance by the public agency of a discretionary contract, grant, subsidy, loan, or other form of financial assistance, lease, permit, license, certificate, or other entitlement for use of the project." Section 21067 of the CEQA statute states, "'Lead agency' means the public agency which has the principal responsibility for carrying out or approving a project which may have a significant effect upon the environment." Although the CAISO approves transmission solutions and selects project sponsors through its transmission planning process, the CPUC is the lead agency for the purpose of CEQA compliance, and must consider alternatives to a proposed project pursuant to CEQA.

Pursuant to Section 15126.6(a) of the CEQA Guidelines, an EIR "shall describe a range of reasonable alternatives to the project" or its location "which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects". Section 15126.6(f) of the CEQA Guidelines establishes a "rule of reason": "The range of alternatives required in an EIR is governed by a "rule of reason" that requires the EIR to set forth only those alternatives necessary to permit a reasoned choice. The alternatives shall be limited to ones that would avoid or substantially lessen any of the significant effects of the project. Of those alternatives, the EIR need examine in detail only the ones that the lead agency determines could feasibly attain most of the basic objectives of the project." Although the basic objectives of a project may be known following the completion of a CAISO transmission plan, the significant effects of that project would not have been studied as part of the TPP, leaving the CEQA process to identify potential significant effects that may inform the alternatives analysis. In addition, Section 15126.6(f) provides that that the range of feasible alternatives "shall be selected and discussed in a manner to foster meaningful public participation and informed decision making" through the CEQA process.

The following proposals address potential modifications to Section IX to comport with the requirements of AB 1373 and to incorporate the concept of rebuttable presumption into GO 131-D.

3.3.2 Proposals

Proposal 1: Establish Rebuttable Presumption for CAISO-Approved Projects Pursuant to AB 1373

This proposal would modify Section IX of GO 131-D to establish a new Section IX.C.2 and IX.C.3 which would establish a rebuttable presumption in favor of CAISO transmission plan findings pursuant to AB 1373 (Garcia, 2023).

First, the proposal would add Section IX.C.2 to introduce the subsequent subsections "a" and "b". The text of Section IX.C.2 would read as follows:

1. <u>Where the electric project proposed in a CPCN or PTC application has been evaluated and approved by the California Independent System Operator (CAISO) in a transmission plan prepared in accordance with the CAISO tariff approved by the Federal Energy Regulatory Commission (FERC):</u>

Second, the proposal would create a new Section IX.C.2.a which would specify that the statement of objectives and any statement of overriding considerations in a CPUC CEQA document prepared for a CAISO-approved transmission project should include the CAISO objectives and purpose for that project outlined in the associated transmission plan(s). The text of Section IX.C.2.a would read as follows:

a. The statement of objectives required by 14 Cal. Code Regs. § 15124(b) in a CEQA document for the proposed project should consider the underlying purpose and project benefits of the proposed project as stated in the relevant CAISO transmission plan.

Third, the proposal would create a new Section IX.C.2.b which would stipulate, pursuant to AB 1373 and Public Utilities Code Section 1001.1, that the CPUC shall establish a rebuttable presumption in favor of the CAISO need evaluation when evaluating the issuance of a CPCN for a proposed transmission project, provided the project meets certain criteria specified in Public Utilities Code Section 1001.1. The text of Section IX.C.2.b would read as follows:

b. In a proceeding evaluating the issuance of a CPCN for a proposed transmission project, if all the provisions of Section IX.C.3 are satisfied, the Commission shall establish a rebuttable presumption in favor of a CAISO governing board-approved finding that such project is needed.

Finally, the proposal would create a new Section IX.C.3 to clarify the applicability of Section IX.C.2.b pursuant to AB 1373 and Public Utilities Code Section 1001.1. The text of Section IX.C.3 would read as follows:

2. Section IX.C.2.b shall apply only to proceedings where:
    a. The CAISO governing board has made explicit findings regarding the need for the proposed transmission project and has determined that the proposed project is the most cost-effective transmission solution.
    b. The CAISO is a party to the proceeding.
    c. The CAISO governing board-approved need evaluation is submitted to the Commission within sufficient time to be included within the scope of the proceeding.
    d. There has been no substantial change to the scope, estimated cost, or timeline of the proposed transmission project as approved by the CAISO governing board.

Staff recommend adoption of Proposal 1. The rationale for the staff recommendation is provided in Section 3.3.4 below.

Proposal 2: Adopt Settling Parties' Proposal to Establish Rebuttable Presumption for CAISO-Approved Projects

This proposal would modify Section IX of GO 131-D to establish a new Section IX.C.2 and IX.C.3 as proposed by settling parties in Attachment A of the Joint Motion for Adoption of Phase 1 Settlement Agreement, which would establish a rebuttable presumption in favor of CAISO transmission plan findings but would also include additional requirements limiting the CPUC's consideration of project alternatives.

First, the proposal would add Section IX.C.2 to introduce the subsequent subsections "a" through "d". The text of Section IX.C.2 would read as follows:

2. The Commission, the California Energy Commission (CEC) and the California Independent System Operator (CAISO) coordinate on electric load forecasting, resource planning and transmission planning to achieve state reliability and policy goals. Pursuant to a stakeholder process set forth in its Federal Energy Regulatory Commission (FERC) tariff, the CAISO conducts electric transmission planning to meet resource needs identified by the Commission, including analysis of alternatives to transmission projects. Therefore, where the electric project proposed in a CPCN or PTC application has been evaluated and approved by the CAISO in a Transmission Plan prepared in accordance with the CAISO tariff approved by FERC:

Second, the proposal would create a new Section IX.C.2.a which would specify that the statement of objectives and any statement of overriding considerations in a CPUC CEQA document prepared for a CAISO-approved transmission project should include the CAISO objectives and purpose for that project outlined in the associated transmission plan(s). The text of Section IX.C.2.a would read as follows:

a. The statement of objectives required by 14 Cal. Code Regs. § 15124(b) and any statement of overriding considerations required by 14 Cal. Code Regs. § 15093(b) in a CEQA Document for the proposed project shall include the underlying purpose and project benefits of the proposed project as stated in the relevant CAISO Transmission Plan.

Third, the proposal would create a new Section IX.C.2.b which would limit the range of reasonable alternatives considered in the CPUC CEQA process for CAISO-approved projects to the "no action" alternative and different feasible routes or locations to construct the project approved by CAISO. For example, reasonable alternatives would be different routes for a transmission line connecting two substations identified by CAISO, but not a transmission line connecting other substations or some other solution. The text of Section IX.C.2.b would read as follows:

b. The range of reasonable alternatives to the proposed project, if any, required by 14 Cal. Code Regs. § 15126.6 in an initial draft CEQA Document for the proposed project circulated for public comment, shall be limited to alternative routes or locations for construction of the relevant CAISO Transmission Plan-approved electric project.

Fourth, the proposal would create a new Section IX.C.2.c which would establish a rebuttable presumption limiting the CPUC's consideration of Public Utilities Code Section 1002.3 "preferred resources" as an alternative to a CAISO-approved project to the analysis in the relevant CAISO transmission plan or the base resource portfolio that the CPUC provided to the CAISO for development of that plan. The text of Section IX.C.2.c would read as follows:

c. There shall be a rebuttable presumption that the consideration of cost-effective alternatives to transmission facilities required by Public Utilities Code Section 1002.3, if applicable, may be limited to the analysis of such alternatives to the proposed project as set forth in the relevant CAISO Transmission Plan and the base resource portfolio provided by the Commission to CAISO for development of that Transmission Plan.

Fifth, the proposal would create a new Section IX.C.2.d which would stipulate, pursuant to AB 1373 (Garcia, 2023), that the CAISO approval of a project in a transmission plan establishes a rebuttable presumption that the public convenience and necessity require the CPUC to approve the project, provided the project meets certain criteria established in Section IX.C.3. The text of Section IX.C.2.d would read as follows:

d. Where such an electric project is the subject of a CPCN application, the CAISO's approval of such project shall establish a rebuttable presumption that such project is necessary to promote the safety, health, comfort, and convenience of the public, and that public convenience and necessity require project approval.

Finally, the proposal would create a new Section IX.C.3 to clarify the applicability of Section IX.C.2.d by providing criteria from AB 1373 to establish which projects are eligible. The text of Section IX.C.3 would read as follows:

3. Section IX.C.2.d shall apply only to proceedings where:
    a. The CAISO governing board has made explicit findings regarding the need for the proposed transmission project and has determined that the proposed project is the most cost-effective transmission solution.
    b. The CAISO is a party to the proceeding.
    c. The CAISO governing board-approved need evaluation is submitted to the Commission within sufficient time to be included within the scope of the proceeding.
    d. There has been no substantial change to the scope, estimated cost, or timeline of the proposed transmission project as approved by the CAISO governing board.

Staff do not recommend adoption of this proposal. The rationale for the staff recommendation is provided in Section 3.3.4 below.

3.3.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1: Staff recommend adoption of Proposal 1. The rationale for the staff recommendation is provided in Section 3.3.4 below.

Proposal 2: Staff do not recommend adoption of this proposal. The rationale for the staff recommendation is provided in Section 3.3.4 below.

3.3.4 Rationale for Staff Recommendations

Staff recommend adopting Proposal 1, and recommend against the adoption of Proposal 2, for the following reasons:

- **The settling parties' proposed Section IX.C.2 includes discussion of the roles of the CPUC, CEC, and CAISO.** The settling parties' proposed Section IX.C.2 (outlined in Proposal 2) includes several sentences explaining the CAISO's transmission planning process and the coordination that occurs between the CPUC, CEC, and CAISO. These sentences are not essential to the implementation of the clause and have been omitted from Proposal 1.
- **Limiting the range of reasonable alternatives (as in the settling parties' proposed Sections IX.C.2.b and IX.C.2.c) would potentially be inconsistent with the level of alternatives analysis required of the Commission under CEQA and NEPA and could constrain the Commission's ability to fully evaluate alternatives including non-wires alternatives.** The settling parties' proposed Section IX.C.2.b would limit the range of reasonable alternatives to a proposed project considered in a draft CEQA document to alternative routes or locations for construction of the relevant CAISO-approved project. The settling parties' proposed Section IX.C.2.c would establish a rebuttable presumption limiting the consideration of cost-effective alternatives to transmission facilities required by Public Utilities Code Section 1002.3 to the alternatives analyzed in the relevant CAISO Transmission Plan and the underlying base resource portfolio. By constraining the alternatives analysis, the settling parties' proposal would impede the CPUC's ability to comply with CEQA; would be inconsistent with the robust alternatives analysis required by the National Environmental Policy Act (NEPA) for projects with federal involvement; and would constrain the CPUC's ability to evaluate non-wires alternatives to proposed transmission projects. The Commission can and should use analysis by CAISO where it can contribute to CEQA and NEPA analysis, but the Commission is obligated to use it within the context of its own independent analysis. As such, the settling parties' proposed Section IX.C.2.b and IX.C.2.c text is omitted from Proposal 1.
    - The Coalition of Utility Employees (CUE) asserts that the settling parties' proposed Section IX.C.2 violates CEQA: "CEQA requires a lead agency to provide a discussion of project alternatives that allows a meaningful analysis. … The Settlement Agreement would prevent the Commission, as lead agency for a transmission project, from complying with its CEQA obligations by artificially limiting the scope of the Commission's alternatives analysis. CEQA does not permit the Commission to rely on a predetermined set of alternatives identified by CAISO, which is neither a public agency nor conducting a CEQA analysis when it prepares its Transmission Plan." (*Comments of the Coalition of California Utility Employees on Phase 1 Settlement Agreement*, October 30, 2023, at 6-7)
    - CUE additionally asserts that the restricting the range of reasonable alternatives as proposed by the settling parties would be infeasible for projects with federal agency involvement due to the robust alternatives analysis required by NEPA: "Moreover, where a project crosses federal land, there will be a [NEPA] analysis and, therefore, any attempt to curtail the alternatives analysis will be futile. NEPA requires a more robust alternatives analysis than does CEQA." (*Comments of the Coalition of California Utility Employees on Phase 1 Settlement Agreement*, October 30, 2023, at 6-7)
    - Cal Advocates asserts, "The settlement does not address whether the CAISO's role would need to change. Specifically, if, as the settlement proposes, the Commission adopts the

CAISO's alternatives analysis, CAISO's Transmission Plan may need to develop a range of alternatives that include route, location, siting, and environmental review of those alternatives. If the CAISO's future Transmission Plans included a range of alternatives with route, location, and siting specific information, along with environmental review of the alternatives, the Commission could consider whether its use of CAISO's alternatives analysis satisfied the Commission's obligations under the California Environmental Quality Act (CEQA)." (*Opening Comments of the California Public Advocates Office on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 5, 2024, at 11)

- Cal Advocates further asserts the settling parties' proposed language could constrain the Commission's ability to evaluate non-wires alternatives such as distributed energy resources (DERs) when considering applications for transmission projects: "While AB 1373 requires the Commission to provide CAISO-approved projects a rebuttable presumption of need for CPCNs when certain requirements are met, the Commission should evaluate whether DERs provide alternatives to transmission project applications that propose to construct wires. This is because CAISO planning activities have generally focused on recommending transmission-based solutions and not DER options." (*Reply Comments of the California Public Advocates Office on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 12-13)
- As asserted by the Center for Biological Diversity and Clean Coalition, "CAISO relies on the Commission's techno-economic screens to project feasible non-wires alternatives, yet those screens exclude substantial areas suitable for rooftop solar and other DERs, including urbanized industrial areas. … Overlooking this potential also ignores significant opportunities for community solar plus storage projects that provide significant benefits to environmental justice communities. … The Settlement Agreement would, in various forms, hold the Commission to CAISO's analysis despite the shifting nature of the non-transmission alternatives landscape, the promise of DERs, and the need to remain flexible in light of new opportunities to deploy non-wires alternatives. CAISO itself noted the importance of environmental review done in addition to its own transmission planning. The Proposed Settlement goes the opposite direction, restraining or limiting the Commission's discretion." (*Center for Biological Diversity and Clean Coalition Opposition to Joint Motion for Adoption of Phase 1 Settlement Agreement*, October 30, 2023, at 15-16)
- The Acton Town Council asserts that it is essential for the CPUC to revisit CAISO determinations of project need: "Settling Parties also argue that … certain CAISO findings pertaining to alternatives and project should not be revisited (page 31). There are several deficiencies in this argument: First, the spectrum of alternatives considered in CAISO's TPP is truncated and does not typically extend to non-transmission alternatives; therefore, CAISO findings pertaining to alternatives should always be "revisited". Second, CAISO is not subject to § 1002.3 of the Public Utilities Code and is not mandated to develop non-transmission alternatives for the projects it approves; therefore, CAISO's alternatives analyses are generally too anemic to comply with § 1002.3 requirements and must be "revisited". Third, CAISO does not consider the impact of its decisions on ratepayers and it

does not factor in ratepayer interests when it declares that a project is "needed" … It is therefore essential to "revisit" CAISO decisions regarding project need." (*Comments by the Acton Town Council Opposing the Joint Motion for Adoption of Phase 1 Settlement Agreement and Contesting Adoption of the Proposed Phase 1 Settlement Agreement*, October 30, 2023, at 13-14)

- As CAISO explains in its opening comments to the R.23-05-018 OIR, the CEQA process allows for the evaluation of alternatives that meet the same reliability needs as the CAISO-approved project: "[the] California Environmental Quality Act (CEQA) process evaluates routing and environmental impacts separate from the CAISO transmission planning process. The CEQA process also allows for stakeholder engagement and for the identification of alternatives that meet the same reliability needs. In some instances, the routing for a project changes through this process to reflect the needs and interests of impacted communities." (*Opening Comments of the California Independent System Operator Corporation on the Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, June 22, 2023, at 4)
- Pursuant to Section 15126.6(a) of the CEQA Guidelines, an EIR "shall describe a range of reasonable alternatives to the project" or its location "which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects". By constraining the CPUC's ability to consider alternatives beyond those analyzed by the CAISO, the settling parties' proposed language could foreseeably conflict with the CEQA Guidelines' mandate to consider alternatives that would avoid or substantially lessen any significant effects. The Acton Town Council asserts, "These CEQA provisions require the Commission to consider alternatives to the project itself and not merely alternatives that address how the project is configured. Settling Parties' proposed addition to Section IX of GO 131 facially violates CEQA provisions related to Lead Agency consideration of project alternatives". (*Comments by the Acton Town Council Opposing the Joint Motion for Adoption of Phase 1 Settlement Agreement and Contesting Adoption of the Proposed Phase 1 Settlement Agreement*, October 30, 2023, at 16)

- **The settling parties' proposed Section IX.C.2.d, which includes a statement that CAISO approval would "require project approval" by the CPUC, could constrain the CPUC's responsibility to comply with CEQA and NEPA.** AB 1373 modified Section 1001.1 of the Public Utilities Code to state that in a CPCN proceeding for a proposed transmission project, the CPUC "shall establish a rebuttable presumption with regard to need for the proposed transmission project in favor of [a CAISO-approved] need evaluation" if the four criteria listed in Public Utilities Code Section 1001.1(a)-(d) are satisfied. Although the settling parties' proposed new GO 131 Section IX.C.3 (outlined in Proposal 2) would mirror the criteria established in Public Utilities Code Section 1001.1(a)-(d), the settling parties' proposed new GO 131 Section IX.C.2.d (to which the proposed Section IX.C.3 criteria would apply) would state that the CAISO's approval of a project establishes a rebuttable presumption of public convenience and necessity that would "require project approval" by the CPUC. The settling parties' proposed text could be interpreted to remove the CPUC's discretionary authority to approve or deny CPCN applications for proposed electrical transmission projects, impeding the CPUC's responsibility to use those powers to avoid or mitigate significant environmental impacts.

- Section 15357 of the CEQA Guidelines defines a "discretionary project" as one "which requires the exercise of judgment or deliberation when the public agency or body decides to approve or disapprove a particular activity". Section 15040 of the CEQA Guidelines states that CEQA supplements an agency's discretionary powers "by authorizing the agency to use the discretionary powers to mitigate or avoid significant effects on the environment when it is feasible to do so with respect to projects subject to the powers of the agency." By removing the CPUC's discretion to approve or deny CPCN applications for CAISO Transmission Plan projects, the settling parties' proposed Section IX.C.2.d would impede the CPUC's ability to use those discretionary powers to mitigate or avoid any potentially significant environmental impacts associated with those projects.
- Section 15352(b) of the CEQA Guidelines states, "With private projects, approval occurs upon the earliest commitment to issue or the issuance by the public agency of a discretionary contract, grant, subsidy, loan, or other form of financial assistance, lease, permit, license, certificate, or other entitlement for use of the project." Adopting the settling parties' proposed Section IX.C.2.d in the next version of GO 131-D could be interpreted to constitute a "commitment to issue" the discretionary certificate for an unknowable number of future proposed transmission projects.

- **Adopting more extensive amendments beyond the requirements of AB 1373 (as proposed in the settling parties' proposed Sections IX.C.2.b, IX.C.2.c, and IX.C.2.d) could impede the Commission's responsibility to consider stakeholder feedback regarding cost and need.**
  - Cal Advocates asserts that the Commission's consideration of cost and need is not redundant with the CAISO's role, but rather provides an important additional forum for stakeholder feedback: "For example, some commentors assert that the Commission's consideration of cost and need is redundant because the CAISO extensively reviews and analyzes projects based on the stakeholder feedback it receives during its [TPP]. While it is true that the TPP involves stakeholder input, the CAISO does not have a mandate to incorporate stakeholder feedback into its Transmission Plan. In fact, the CAISO is not even obligated to explain why it rejects stakeholder feedback — a concern that Cal Advocates has expressed to the Commission and the CAISO. If transmission projects are allowed to bypass Commission review of cost and need completely, ratepayer advocates and the public would lose a critical venue to offer feedback and express concerns. In addition, the CAISO does not review and approve all transmission projects that go through the Commission's permitting process." (*Reply Comments of the California Public Advocates Office on the Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, July 7, 2023, at 5-6)
- Furthermore, citing Public Utilities Code Section 701 ("The commission may supervise and regulate every public utility in the State and may do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction."), Cal Advocates asserts, "Beyond determining whether a project is needed, the Commission also has broad authority to consider when a CAISO-approved project is needed." (*Reply Comments of the California Public Advocates Office on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 13)

3.4 Clarify Advice Letter Protest Process

3.4.1 Problem Statement

In adopting the original version of GO 131-D in 1994, the CPUC established a process in Section XIII by which a person or entity receiving notice of an advice letter claiming an exemption from a PTC, or any person or entity entitled to participate in a proceeding for a PTC, can protest the claim if such persons or entities have a valid reason to believe that any of the conditions described in Section III.B.2 exist or the utility has incorrectly applied an exemption as defined in Section III. Section XIII allows the Executive Director to issue an Executive Resolution on whether the utility is to file an application for a permit to construct or whether the protest is dismissed for failure to state a valid reason. Section XIII requires the Executive Director to state the reasons for granting or denying the protest and provide a copy of each Executive Resolution to the Commission's Public Advisor.

However, CPUC GO 96-B, first adopted in 2001, sets forth CPUC rules related to the processing of advice letters. GO 96-B General Rule 7.6.2 provides for the disposition of protests to advice letters by full Commission vote at an agendized meeting except for the cases in which, as provided in General Rules 5.3, 7.5.1, or 7.6.1, the Energy Division may approve or reject an advice letter. Energy Division staff currently follow the procedures outlined in GO 96-B for disposition of protests to advice letters.

Settling parties, in the Joint Motion for Adoption of Phase 1 Settlement Agreement, argue that this practice of bringing protested advice letters to a Commission vote could delay construction of critical infrastructure projects by several months while CPUC staff review the matter and identify the appropriate time for it to be considered at an agendized meeting. Therefore, the settling parties propose revisions to Section XIII to allow staff-level disposition of all advice letter protests despite the direction in GO 96-B. In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties propose requiring that protests be filed in compliance with Rule 2.6 of the Commission's Rules of Practice and Procedure rather than in compliance with General Order 96-B. However, Rule 2.6 of the Commission's Rules of Practice and Procedure establishes procedures for protests of filed applications rather than protests of advice letters.

3.4.2 Proposals

Proposal 1: Retain Executive Resolution Process and Clarify Appeal Process

This proposal would retain the Executive Resolution process currently described in Section XIII of GO 131-D, but would amend Section XIII to clarify that protesters may request Commission review of the Executive Director's or Energy Division's disposition of an advice letter pursuant to General Order 96-B, General Rule 7.6.3.

Section XIII would be modified as follows, with new text underlined in red:

Those to whom notice has been given under Section XI.B hereof and any other person or entity entitled to participate in a proceeding for a permit to construct may, within 20 days after the notice was mailed and published, contest any intended construction for which exemption is claimed by the utility from the requirements of Section III.B if such persons or entities have valid reason to believe that any of the conditions described in Section III.B.2 exist or the utility has incorrectly applied an exemption as defined in Section III herein. The protest shall be filed with the Energy Division, specifying the relevant utility advice letter number, in accordance with General Order 96-B, Sections 3.11, 7.4.1, and 7.4.2. On the same date a protest is filed with the Commission, the protestant shall serve a copy on the subject utility by mail. The utility shall respond within five business days of receipt and serve copies of its response on each protestant and the Energy Division. Construction shall not commence until the Executive Director has ~~issued an Executive Resolution~~ disposed of the protest.

Within 30 days after the utility has submitted its response, the Executive Director, after consulting with the Energy Division, shall issue a~~n Executive Resolution~~ disposition letter on whether: the utility is to file an application for a permit to construct, or the protest is dismissed for failure to state a valid reason. Also, the Executive Director shall state the reasons for granting or denying the protest and provide a copy of ~~each Executive Resolution~~ the disposition letter to the Commission's Public Advisor.

The utility, any persons that filed a protest to the advice letter, or other persons or entities (to the extent authorized by General Order 96-B or its successor regulation) may request Commission review of the Executive Director's or Energy Division's disposition of an advice letter, pursuant to General Order 96-B, General Rule 7.6.3 (or a successor regulation).

The Commission's Public Advisor shall provide information to assist the public in submitting such protests.

Staff recommend Proposal 1. The rationale for the staff recommendation is provided in Section 3.4.4 below.

Proposal 2: Retain Executive Resolution Process

This proposal would make no changes to the Section XIII of GO 131-D, retaining the Executive Resolution process as recommended by the settling parties in the Joint Motion for Adoption of Phase 1 Settlement Agreement.

In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties proposed replacing a reference to General Order 96-A, Section III.H with a reference to Rule 2.6 of the Commission's Rules of Practice and Procedure. However, Rule 2.6 refers to protests of filed applications rather than protests of advice letters, and therefore is not applicable to the GO 131-D advice letter process. Furthermore, in Decision 23-12-035, the Commission already replaced the reference to General Order 96-A with a reference to General Order 96-B, Sections 3.11, 7.4.1, and 7.4.2. As such, Proposal 2 has been developed as a "no action" option to consider the settling parties' recommendation to retain the Executive Resolution process, but does not include other components of the settling parties' proposal that would not be appropriate to implement.

Staff do not recommend adopting Proposal 2 at this time. The rationale for the staff recommendation is provided in Section 3.4.4 below.

3.4.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1: Staff recommend Proposal 1. The rationale for the staff recommendation is provided in Section 3.4.3 below.

Proposal 2: Staff do not recommend adopting Proposal 2 at this time. The rationale for the staff recommendation is provided in Section 3.4.3 below.

3.4.4 Rationale for Staff Recommendations

Staff recommend adopting Proposal 1 for the following reasons:

- **Proposal 1 would retain the option for CPUC staff to dispose of protests without a Commission resolution while providing a process for CPUC review consistent with GO 96-B.** In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties assert, "At a minimum, Commission staff should avoid a policy of resolving all protests by Commission resolution, and instead incorporate reasonable options for its staff to dispose of protests without one." (*Joint Motion for Adoption of Phase 1 Settlement Agreement,* September 29, 2023, at 47) This proposal would satisfy that request while updating Section XIII to provide a process for Commission review of protested advice letters, consistent with GO 96-B.
- **Parties expressed opposition to requiring a full Commission vote for all advice letter protests (in lieu of a staff-level disposition or Executive Resolution process), as proposed in Attachment B to the R.23-05-018 OIR.** Unlike the proposed changes included in OIR Attachment B, Proposal 1 would provide an option for protestors to request Commission review of the Executive Director's or Energy Division's disposition of an advice letter, pursuant to General Order 96-B, but would not require that advice letter protests be handled by Commission vote.
    - In its opening comments on the R.23-05-018 OIR, CUE stated, "Attachment B would also revise the process for protesting advice letters filed pursuant to GO 131-D. Historically and currently, Commission staff evaluates whether a project qualifies for an exemption under GO 131-D and the Commission's Executive Director makes the final determination within 30 days. The proposed revision would instead require the full Commission to evaluate whether a project is exempt and make a final determination through a noticed and agendized vote. This will likely add several months to the process which, again, is contrary to the intent

of SB 529." (*Opening Comments of the Coalition of California Utility Employees on Order Instituting Rulemaking*, June 22, 2023, at 6-7)

- In its opening comments on the R.23-05-018 OIR, the Large-Scale Solar Association stated, "Attachment B would remove PTC exemptions for projects with low environmental hurdles, require a Tier 2 advice letter for a Notice to Construct instead of a Tier 1, and require full Commission vote on protests challenging a PTC v. CPCN designation when today the Energy Division can decide. These changes may remove some perceived ambiguity and increase oversight for CPUC staff, but they would also remove existing pathways for expedited treatment and increase opportunities for protest and delay, which would move the permitting process in the opposite direction from the intent of SB 529." (*Opening Comments of the Large-Scale Solar Association on the Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, June 22, 2023, at 3-4)
- In its opening comments on the R.23-05-018 OIR, SCE asserts, "As recognized in the Commission's initial decision adopting GO 131-D, given the unique and often intricate role of CEQA and environmental issues associated with development projects, the Executive Director (as assisted by CPUC staff) is in the best position to evaluate a particular project's characteristics and compare them to established GO 131-D principles, regardless whether GO 96-B provides for a different process applicable to other types of proceedings. In its decision adopting GO 131-D, the CPUC noted that the utilities raised concerns that requiring full proceedings for protests to exemptions could lead to delays of worthy and urgently needed project completions "for the price of a postcard." Reversing that procedure now, and requiring such decisions to be made by the full Commission – via a noticed and agendized procedural vote that may not occur for several months after an Advice Letter is filed – would negate that well-reasoned and well-implemented process and needlessly delay important projects designed to accommodate, among other things, renewable energy resources in line with State policy. That process also could lead to a voluminous number of seemingly routine exemption determinations coming before the full Commission at every business meeting." (*Southern California Edison Company's (U 338-E) Comments on Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, June 22, 2023, at 15-16)

Staff recommend against the adoption of Proposal 2 for the following reasons:

- **Updating Section XIII to cite Rule 2.6, as proposed by the settling parties, would be inappropriate as Rule 2.6 applies to filed applications, not protests of advice letters.** In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties propose amending Section XIII to require that protests be filed in compliance with Rule 2.6 of the Commission's Rules of Practice and Procedure rather than in compliance with General Order 96-B. However, Rule 2.6 of the Commission's Rules of Practice and Procedure establishes procedures for protests of filed applications rather than protests of advice letters. Instead, in the Decision Addressing Phase 1 Issues (D.23-12-035), the Commission updated the same sentence to require that protests be filed "in accordance with General Order 96-B, Sections 3.11, 7.4.1, and 7.4.2." For this reason, Proposal 2 does not include the settling parties' proposed reference to Rule 2.6, and is simply a "no action" option.

3.5 Clarify Permitting of Battery Storage Facilities

3.5.1 Problem Statement

Battery storage facilities, also known as battery energy storage systems (BESS), are energy storage power stations that use batteries to store electrical energy. BESS are often constructed at or adjacent to electrical generating facilities, and may share the same connection to the electrical grid. As California accelerates the development of renewable generation (e.g., utility-scale solar and wind) and expands the capacity of the state's electrical grid to meet the SB 100 clean energy targets and ensure grid reliability, battery storage facilities are increasingly being used to supplement transmission solutions. As CUE observed in its opening comments on the R.23-05-018 OIR, "In the [2021] SB 100 report, the CEC, Commission and [California Air Resources Board (CARB)] found that to meet our [100% clean electricity] goals, California will have to roughly triple its electricity capacity, triple the build rate for solar and wind resources and increase the build rate for battery storage eightfold." (*Comments of the Coalition of California Utility Employees on Order Instituting Rulemaking*, June 22, 2023, at 1-2) In February 2024, the CPUC adopted its 2024-2025 Integrated Resource Planning (IRP) Preferred System Plan and Portfolio, which estimates the future installation of 22 gigawatts (GW) of battery storage projects by 2030, including storage and hybrid solar/storage, and 32 GW by 2035.[11]

The historical trend for the siting and development of battery storage facilities has involved distributed projects throughout local communities proposed by private developers or third parties such as independent power producers (IPPs) that then sell electricity to utilities through power purchase agreements (PPAs). In its opening comments on the R.23-05-018 OIR, Rev Renewables asserts that "the vast majority (estimated ~90%) of battery storage projects built today have been done by Independent Power Producers (IPPs)." (*Rev Renewables, LLC Opening Comments on the Order Instituting Rulemaking on General Order 131-D*, June 22, 2023, at 3) Local agencies have historically served as the lead land use agency (including as the lead CEQA agency) in these circumstances. Local agency approvals have varied widely throughout California. In some jurisdictions, local agencies have fast-tracked development of BESS through use of CEQA exemptions, ministerial land use permits, and building permits. In other areas, local agencies have favored denials, moratoria, and prohibitions of BESS. The latter approach has contributed to delays in the implementation of battery energy storage technology.

Partly in response to these delays, AB 205 (Ting, 2022) expanded the siting authority of the CEC to make the CEC the lead CEQA agency for any project where an entity (including public utilities and IPPs)

[11] The CPUC's Integrated Resource Planning (IRP) process was established to set electricity resource planning targets for CPUC-jurisdictional Load Serving Entities within the CAISO's jurisdiction.

proposes eligible energy storage facilities with a capacity of 200 Megawatt-hours (MWh) or more, along with certain manufacturing facilities for energy storage and renewable energy systems, several categories of clean energy generation facilities, and transmission lines carrying electricity from those facilities to the first point of interconnection. AB 205 provided that until June 30, 2029, applicants seeking to construct such facilities may "opt in" to file an application for certification (AFC) with the CEC, upon receipt of which the CEC would have the exclusive power to certify the project.

Public Resources Code Section 25545.1(a) states that the AB 205 certification process (i.e., wherein the CEC may become the lead agency for eligible projects) does not modify the CPUC's existing jurisdiction for facilities proposed by utilities regulated by the CPUC. However, utilities regulated by the CPUC may nonetheless choose to pursue the CEC's AFC process for eligible projects pursuant to AB 205.

> A person proposing an eligible facility may file an application no later than June 30, 2029, for certification with the commission to certify a site and related facility in accordance with this chapter, including a person who has an application for certification or small powerplant exemption filed with the commission pursuant to Chapter 6 (commencing with Section 25500) pending as of the effective date of this section. Upon receipt of the application, the commission shall have the exclusive power to certify the site and related facility, whether the application proposes a new site and related facility or a change or addition to an existing facility. This section does not modify the Public Utilities Commission's jurisdiction, including the issuance of a certificate of public convenience and necessity under Chapter 5 (commencing with Section 1001) of Part 1 of Division 1 of the Public Utilities Code for a facility that is proposed by a utility regulated by the Public Utilities Commission. (Public Resources Code Section 25545.1(a))

Public Resources Code Section 25545 establishes that one type of facility eligible for the AB 205 process is "an energy storage system as defined in Section 2835 of the Public Utilities Code that is capable of storing 200 megawatthours or more of electrical energy." Public Utilities Code Section 2835 defines an "energy storage system" as "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy", which may be centralized or distributed; may be owned by a load-serving entity or local publicly owned electric utility, a customer of a load-serving entity or local publicly owned electric utility, and/or third party; and which must do one or more of the following:

A. Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.
B. Store thermal energy for direct use for heating or cooling at a later time in a manner that avoids the need to use electricity at that later time.
C. Use mechanical, chemical, or thermal processes to store energy generated from renewable resources for use at a later time.
D. Use mechanical, chemical, or thermal processes to store energy generated from mechanical processes that would otherwise be wasted for delivery at a later time.

In the R.23-05-018 OIR, the Commission included a preliminary scoping memo which asked, among other questions, whether the CPUC should modify GO 131-D to create a process for permitting battery storage.

(*Order Instituting Rulemaking 23-05-018,* May 22, 2023, at 4) In addition, OIR Attachment B contained proposed amendments to GO 131-D to create a process for permitting battery storage projects.

Specifically, OIR Attachment B contained proposed amendments to GO 131-D that would have required that "battery storage facilities greater than 50 MW" and also "outside of existing substations" constructed by electric public utilities subject to, or that may become subject to, CPUC jurisdiction would be required to obtain a PTC from the CPUC. Attachment B also clarified that "local jurisdictions acting pursuant to local authority are preempted from regulating battery storage facilities by public utilities subject to CPUC jurisdiction." After receiving party input on Attachment B in the opening and reply comments on the OIR (summarized in Section 3.5.4 of this staff proposal, Rationale for Staff Recommendations), the Commission, in the Scoping Memo and Ruling filed July 31, 2023, established that the battery energy storage issue would be addressed in Phase 2 of the R.23-05-018 proceeding.

On September 29, 2023, the settling parties submitted the Joint Motion for Adoption of Phase 1 Settlement Agreement. Although various settling parties have commented on the battery energy storage issue (see Section 3.5.4 of this staff proposal), the settlement agreement itself is silent on whether the CPUC should create a process for permitting battery storage projects, and does not propose specific modifications to GO 131-D that would create a process for permitting these projects.

The current version of GO 131-D is silent on regulation of "energy storage systems" per se. However, this technology clearly falls under the definition of "electric facilities." Section XIV of GO 131-D clarifies that local authorities are preempted from regulating electric facilities constructed by public utilities subject to the CPUC's jurisdiction. This preemption would apply to electric facilities jointly owned and constructed by both public utilities subject to CPUC jurisdiction and non-public-utility entities (e.g., IPPs). However, the CPUC cannot preempt local authorities from regulating electric facilities constructed solely by non-public-utility entities (e.g., IPPs).

Although the CPUC preempts local agencies in regulating electric facilities proposed by public utilities subject to CPUC jurisdiction, Section XIV.B of GO 131-D requires public utilities to "consult with local agencies regarding land use matters associated with locating such projects." As a result, public utilities often secure building, grading, and drainage permits from local agencies for construction of their projects as a means to consult and coordinate with local agencies. In instances where the public utilities and local agencies are unable to resolve their differences, the CPUC shall set a hearing no later than 30 days after the CPUC has been notified of the inability to agree on land use matters pursuant to Section XIV.B of GO 131-D. In addition, public agencies or other interested parties may contest the construction of electric facilities by filing a complaint with the Commission pursuant to Section XIV.C of GO 131-D and Article 4 of the CPUC's Rules of Practice and Procedures.

With regard to ensuring the safety of battery storage facilities, SB 1383 (Hueso, 2022) requires the CPUC to "implement and enforce standards for the maintenance and operation of facilities for the storage of electricity owned by an electrical corporation or located in the State." SB 38 (Laird, 2023) also requires each battery energy storage facility located in the State to have an Emergency Response and Emergency Action Plan and requires the facility owner to coordinate with the local emergency management agencies, unified program agencies, and local first response agencies in preparation of the plan. The CPUC's Electric Safety and Reliability Branch (ESRB) is part of the Safety and Enforcement Division and is responsible for enforcing State statutes, CPUC rules and regulations, and CPUC General Orders regarding the safety and reliability of electric facilities, including SB 1383 and SB 38. The ESRB has determined that energy storage systems are subject to CPUC General Order (GO) 167-B, which establishes operation and maintenance standards for electric generating facilities. The ESRB is in the process of updating GO 167-B to clarify which sections are applicable to battery storage systems and to ensure compliance with SB 1383 and SB 38.

3.5.2 Proposals

Proposal 1: Clarify Permitting Process for Transmission Lines Connecting to Battery Energy Storage Systems

This proposal would clarify the CPUC's role in permitting transmission line components of battery energy storage systems (BESS) proposed by electric public utilities by modifying Section III.A of GO 131-D to include such projects in the definition of "extension" of existing electrical transmission facilities outlined in Section 3.1.2, Proposal 2 of this staff proposal.

As detailed in Section 3.1.2 of this staff proposal, Section III.A would be modified to include the following example of an "extension" of existing electrical transmission facilities, which references energy storage facilities and energy storage developers:

> Construction of a new transmission line from an existing electrical transmission facility to connect to a new energy storage or generation facility, or an over-200 kV generation tie-line (gen-tie) segment, constructed by an independent renewable generator, energy storage developer, or other transmission provider (i.e., the portion of the line that will be owned by the transmission operator)

Staff recommend adoption of this proposal. The rationale for the staff recommendation is provided below in Section 3.5.4 of the staff proposal.

Proposal 2: Clarify Permitting Process for Battery Energy Storage System Substation Upgrades

This proposal would clarify the CPUC's role in permitting BESS projects proposed by electric public utilities within or adjacent to existing substations by modifying Section III.A of GO 131-D to include such projects in the definition of "upgrade" of existing electrical transmission facilities outlined in Section 3.1.2, Proposal 2 of this staff proposal.

As detailed in Section 3.1.2 of this staff proposal, Section III.A would be modified to include the following example of an "upgrade" of existing electrical transmission facilities:

> Adding battery energy storage systems to an existing substation, or expanding an existing substation to include battery energy storage systems

Staff recommend adoption of Proposal 2. The rationale for the staff recommendation is provided below in Section 3.5.4 of the staff proposal.

3.5.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1: Staff recommend adoption of Proposal 1. The rationale for the staff recommendation is provided below in Section 3.5.4 of the staff proposal.

Proposal 2: Staff recommend adoption of Proposal 2. The rationale for the staff recommendation is provided below in Section 3.5.4 of the staff proposal.

3.5.4 Rationale for Staff Recommendations

Staff recommend the adoption of Proposal 1 and Proposal 2 for the following reasons:

- **A range of parties support clarifying a PTC process for energy storage systems.**
    - SDG&E asserts, "SDG&E supports the Commission's assertion of active permitting jurisdiction over certain energy storage systems so long as the Commission also adopts adequate thresholds to a PTC requirement and the revisions set forth in the Settlement Agreement to ensure expedited processing of PTC applications." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 5, 2024, at 23)
    - RCRC states, "RCRC objects to SCE's suggestion that no Commission permit or review should be required for battery storage facilities under 50MW or for facilities located on (or adjacent to) property that is owned by a utility where an existing substation is located. Given the safety risks and local concerns about these facilities, the Commission should review all projects to ensure their consistency with the yet-to-be determined SB 1383/SB 38 standards." (*Reply Comments of Rural County Representatives of California on Phase 2 Issues*, February 26, 2024, at 7)
    - SCE asserts, "In many ways, battery storage facilities resemble substations in terms of size, shape and ground disturbance footprint. Therefore, SCE believes that like substations, battery storage facility projects should be subject only to the same PTC (as opposed to CPCN) requirements as substations, given that the generation purpose of the facility is clear. Environmental considerations under CEQA are the only issues needing review by the Commission." (*Southern California Edison Company's Opening Comments on the Ruling Inviting Comment on Phase 2 Issues, February*, 2024, at 17)
    - SCE further states, "In these Reply Comments, SCE recommends the Commission: … Issue an updated staff proposal with the Scoping Memo for this OIR that includes only the following modifications to GO 131-D: … Adoption of provisions confirming that battery storage facilities exceeding 50 MW are subject to the same PTC requirements (and exemptions thereto) as substations and power line facilities between 50 kV and 200 kV, and

that the Commission's licensing authority preempts local land use regulation of battery storage facilities" (*Southern California Edison Company's (U 338-E) Reply Comments on Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, July 7, 2023, at 2-3)
  - The Large-Scale Solar Association states, "LSA does not oppose consideration of jurisdiction over battery storage permitting in Phase 2 of this proceeding, as recommended by all three Investor-Owned Utilities ("IOUs"). LSA does not have a position at this point on whether this proposal will expedite permitting or not and generally opposes adjustments to 131-D that would result in an uneven playing field for utility v. third party owned battery storage. However, LSA is open to including this concept for discussion." (*Reply Comments of the Large-Scale Solar Association Regarding the Administrative Law Judge Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 5)
  - A notable exception is the Acton Town Council, which asserts that energy storage projects should be subject to the CPCN process (*Reply Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 23).
- **A range of parties support limiting any CPUC permitting jurisdiction for energy storage facilities to the subset of projects proposed by electric public utilities.** Parties have generally expressed agreement that CPUC permitting jurisdiction for energy storage projects should be limited to those proposed by electric public utilities, and that utility-owned energy storage facilities represent a relatively small subset of the battery energy storage projects in California. In comments submitted in response to the R.23-05018 OIR and the ALJs' Ruling Inviting Comment on Phase 2 Issues, several parties including IOUs request that the CPUC explicitly assert preemption over local jurisdiction of battery storage facilities and request that the CPUC directly permit battery storage facilities. However, several parties point out that the CPUC would not be able to preempt local agencies for projects that are not constructed by public utilities subject to CPUC jurisdiction.
  - In its opening comments on the R.23-05-018 OIR, Rev Renewables asserts, "GO 131-D is only applicable to electric public utilities, and therefore this new process would only apply to utility-owned battery storage facilities. The vast majority (estimated ~90%) of battery storage projects built today have been done by Independent Power Producers (IPPs)." (*Rev Renewables, LLC Opening Comments on the Order Instituting Rulemaking on General Order 131-D*, June 22, 2023, at 3)
  - The Independent Energy Producers Association states, "IEP emphasizes that the subjects of GO 131-D are "electric public utilities," not non-utility entities that develop electric facilities. For example, the requirement in section III.A for electrical public utilities to receive a CPCN before beginning construction of "any new electric generating plant having in aggregate a net capacity available at the busbar in excess of 50 megawatts" does not apply to the non-utility entities (many of whom are IEP members) who have developed the bulk of the state's new generation in this century and nearly all of the renewable resources needed to meet California's clean energy goals. Any expansion of GO 131-D to include energy storage facilities should likewise be limited to utility-owned storage facilities." (*Reply Comments of the Independent Energy Producers Association on Phase 2 Issues*, February 26, 2024, at 10)

- SDG&E states, "Given the state's ambitious climate goals, significant amounts of energy storage needed and the build rate at which it is needed, SDG&E plans to continue its utility-owned energy storage development efforts as a complement to third-party power purchase agreements (which have been the bulk of the deployed battery energy storage projects in California to date)." (*Opening Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 5, 2024, at 25)
- Rev Renewables asserts, "IPP projects will still have to go through the normal California Environmental Quality Act (CEQA) process and permitting with the local authority having jurisdiction. This permitting path for IPPs generally takes eighteen to twenty-four months." (*Rev Renewables, LLC Opening Comments on the Order Instituting Rulemaking on General Order 131-D*, June 22, 2023, at 4)

- **Parties are divided on the appropriate capacity threshold for battery storage facilities.** Where parties recommend that the CPUC permit battery storage projects, there is disagreement on the permit type that would be applicable and the MW threshold that would require a permit. The majority of parties expressed a preference that battery storage projects be subject to a PTC rather than a CPCN. For example, in its opening comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues, SCE states that battery facilities resemble substations in terms of size, shape, and ground disturbance footprint, and contends that battery projects only warrant a PTC and, in many instances, should not be subject to permit requirements at all. In opening comments on the R.23-05-018 OIR, SDG&E expressed support for extending the Commission's active permitting jurisdiction to energy storage systems (i.e., not only battery storage), but only to projects over 100 MW and not located on or adjacent to existing utility-owned substation property. However, in its own opening comments on the OIR, POCF asserted that the Commission should limit the battery storage PTC exemption threshold to 5 MW or 20 MWh.
  - In its opening comments on the R.23-05-018 OIR, POCF asserts, "The Commission should also reduce the proposed 50 MW permit to construct exemption threshold for battery storage projects. More important than the discharge capacity of the battery storage project is the battery chemistry and the potential fire hazard. At least one California battery storage project under 50 MW has been denied in the last year at the County level due to concerns by nearby residents regarding the impact on property values, noise pollution, and fire hazard. PCF recommends that the battery storage permit to construct exemption threshold be limited to 5 MW or 20 megawatt-hour (MWh)." (*The Protect Our Communities Foundation Comments on Order Instituting Rulemaking to Update and Amend Commission General Order 131-D*, June 22, 2023, at 5-6)
  - In its opening comments on the R.23-05-018 OIR, Rev Renewables recommends, "If the Commission includes battery storage projects under GO 131-D, at a minimum it should be included under Section III.A for Certificate of Public Convenience and Necessity (CPCN), which already applies to electric generating plants in excess of 50 MW." (*Rev Renewables, LLC Opening Comments on the Order Instituting Rulemaking on General Order 131-D*, June 22, 2023, at 5)
  - SCE asserts, "SCE does not disagree with the Commission's proposed threshold of 50 MW for battery project PTC licensing, although SCE is open to other size or scale thresholds."

(*Southern California Edison Company's Opening Comments on the Ruling Inviting Comment on Phase 2 Issues, February*, 2024, at 16)

- **Party comments support a streamlined permitting process for projects adding energy storage to existing substation infrastructure.**
    - SCE comments, "In discussing energy storage project regulation and potential preemption issues, PG&E suggested that storage projects should be exempt from permitting if located on or immediately adjacent to substation property owned by the utility. SCE agrees with PG&E in this regard, and also suggests that the Commission adopt a similar approach for substation expansion projects, regardless whether there is an energy storage component." (*Southern California Edison's (U 338-E) Reply Comments on the Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 47)
    - SCE further asserts, "Likewise, just as GO 131-D currently states that substation modification projects (including those that do not involve work beyond the existing utility-owned property) do not even require a PTC, the Commission should similarly exempt from licensing any battery storage project located on or adjacent property that is: a) owned by a public utility; and b) where an existing substation is located. Installation of battery facilities on or adjacent to existing substations would serve multiple purposes, including compliance with the Garamendi Principles favoring collocation of utility infrastructure, as well as minimizing environmental impacts (such as ground disturbance for the battery facility and/or transmission line work needed to connect the facility to the broader grid)." (*Southern California Edison Company's Opening Comments on the Ruling Inviting Comment on Phase 2 Issues, February*, 2024, at 17)
    - EDF asserts, "While EDF has renewed its request for a workshop on battery storage to inform any staff proposal and party comments on these issues, at this point EDF would suggest exempting from a PTC only those battery storage projects located adjacent to existing utility-owned substation, energy storge or generation infrastructure. Limiting the exemption to those projects adjacent to existing infrastructure, rather than property, likely aligns with the intent of these proposals, while limiting the possibility that expansive properties would lead to construction far from existing infrastructure being exempt from a PTC." (*Reply Comments of Environmental Defense Fund on Phase 2 Issues*, February 26, 2024, at 7)
- **A range of parties support exempting certain energy storage projects from the PTC process, though some parties strongly opposed exemptions for energy storage.** Although the modifications to GO 131-D proposed in Proposal 1 and Proposal 2 do not explicitly reference a PTC exemption for energy storage, these modifications would clarify that certain categories of energy storage projects (i.e., utility-owned transmission and gen-tie components of energy storage facilities, or siting energy storage within the existing or expanded footprint of a utility-owned substation) would be eligible for the PTC process rather than the CPCN process. Depending on the characteristics of each qualifying project, some of the energy storage projects subject to the GO 131-D Section III.B process pursuant to Proposals 1 and 2 may also be eligible for a PTC exemption pursuant to GO 131-D Section III.B.1. Rather than establishing a capacity threshold for energy storage projects, Proposals 1 and 2 would focus on smaller projects that might be expected to be

exempt from CEQA and/or the PTC requirement, notwithstanding the list of exceptions in GO 131-D Section III.B.2.

- SCE asserts, "The Commission should consider providing an exemption for substation modification projects that involve property immediately adjacent to the existing substation." (*Southern California Edison's (U 338-E) Reply Comments on the Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 48)
- EDF summarizes, "EDF is concerned that some aspects of the PTC thresholds/exemptions proposed by other parties may be unduly broad. In particular, SCE proposes to exempt from PTC requirements "any battery storage project located on or adjacent to property that is a) owned by a public utility, and b) where an existing substation is located." Similarly, SDG&E proposes that a PTC requirement extent only to "an energy storage system and its supporting infrastructure over 100 MW and not located on or adjacent to existing utility-owned property on which electric substation, energy storge or generation infrastructure is located." EDF's concern is that these proposals will not capture battery storage projects that might actually have potentially significant impacts that should be reviewed and mitigated under CEQA. For instance, it is possible that portions of large properties with substations, or adjacent properties, could be undeveloped with sensitive habitat or located near residential uses." (*Reply Comments of Environmental Defense Fund on Phase 2 Issues*, February 26, 2024, at 6-7)
- A notable voice of dissent is RCRC, which asserts, "Given the newness of the technology, proximity to sensitive populations and fuel sources, and significant risks in the event of an emergency, RCRC has very serious concerns about the Commission's efforts to preempt local authority over utility battery energy storage facilities. RCRC even more strongly objects to utility suggestions that facilities under 50MW or 100MW do not need any review by the Commission. Before continuing discussions about preempting local regulation of utility battery storage facilities, we believe that much more work is needed to protect public safety through updating GO 167, integrating the requirements of last year's SB 38 (Laird), and establishing safety planning and review protocols for facilities that are not subject to the Permit to Construct process." (*Reply Comments of Rural County Representatives of California on Phase 2 Issues*, February 26, 2024, at 3)

3.6 Facilitate ROW Sharing Between Incumbent and Non-Incumbent Utilities

3.6.1 Problem Statement

The CAISO, through a competitive solicitation process in its annual TPP, awards electric transmission projects to both incumbent utilities and independent non-incumbent utilities. The availability of right-of-way (ROW) access is a key selection factor in selecting the project sponsor. Incumbent utilities, such as

California's large IOUs, own and maintain electrical transmission infrastructure within existing ROWs to transmit electricity within their service area. When the CAISO assigns an incumbent utility to construct a new electrical transmission project, the incumbent can often site and construct the project within its existing ROWs, enabling a more efficient use of land area. In contrast, non-incumbent utilities are independent entities that are not yet providing electrical service in a given area, and therefore cannot leverage existing ROW agreements to the same extent as incumbent utilities.

In its opening comments on the ALJ's Ruling Inviting Comment on Phase 2 Issues, Cal Advocates proposes that the CPUC amend GO 131-D to incorporate a process that requires ROW sharing between non-incumbent electric utilities and incumbent electric utilities (*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruing Inviting Comment on Phase 2 Issues*, February 5, 2024, at 16). Cal Advocates states that ROW assets are funded by ratepayers and that ROW sharing would be a more efficient and cost-efficient way to build transmission. Cal Advocates states that ROW sharing can reduce project costs and streamline project construction because it would enable non-incumbent electric utilities to: (1) build on already-permitted land; (2) use already-constructed assets; and (3) locate construction on land parcels that have already undergone some form of environmental review. Cal Advocates states that ROW sharing would be consistent with the State's long standing Garamendi Principles outlined in Senate Bill (SB) 2431 (Garamendi, Chapter 1457, Statutes of 1988).[12] Cal Advocates highlights that IOUs use ratepayer funds to obtain ROWs and related assets such as public utility poles, ducts, and conduits. Cal Advocates proposes the use of Joint Use Agreements to facilitate ROW sharing, such as those arrangements used between telecommunications providers and electrical utilities.

Public Utilities Code Section 767 states that the CPUC may order a public utility to allow another public utility to use its ROW or facilities, and prescribe a reasonable compensation and terms and conditions for the joint use, when required by the public convenience and necessity:

> "Whenever the commission, after a hearing had upon its own motion or upon complaint of a public utility affected, finds that public convenience and necessity require the use by one public utility of all or any part of the conduits, subways, tracks, wires, poles, pipes, or other equipment, on, over, or under any street or highway, and belonging to another public utility, and that such use will not result in irreparable injury to the owner or other users of such property or equipment or in any substantial detriment to the service, and that such public utilities have failed to agree upon such use or the terms and conditions or compensation therefor, the commission may by order direct that such use be permitted, and prescribe a reasonable compensation and reasonable terms and conditions for the joint use. If such use is directed, the public utility to whom the use is permitted shall be liable to the

[12] SB 2431 (Garamendi, 1988) enacted state transmission siting policies, known as the Garamendi Principles, which (1) encourage the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically justifiable; (2) when construction of new transmission lines is required, encourage expansion of existing rights-of-way, when technically and economically feasible; (3) provide for the creation of new rights-of-way when justified by environmental, technical, or economic reasons as determined by the appropriate licensing agency; and (4) where there is a need to construct additional transmission capacity, seek agreement among all interested utilities on the efficient use of that capacity.

> owner or other users for such damage as may result therefrom to the property of the owner or other users thereof, and the commission may ascertain and direct the payment, prior to such use, of fair and just compensation for damage suffered, if any." (California Public Utilities Code Section 767)

In its opening comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues, Cal Advocates asserts that its ROW proposal would not pose a takings issue pursuant to the Fifth Amendment due to the provisions of Public Utilities Code Section 762.

> "Finally, the takings clause of the Fifth Amendment is not a barrier to implementing this proposal. A public utility is not a private utility property owner that would suffer personal economic loss because its property is forfeited to a different and public use. Rather, ROW sharing will allow a public utility to construct a project to benefit the public on land that is already used to serve the public in a similar manner. Further, the ROW sharing process will avoid a takings issue because Public Utilities Code section 762 provides that a utility seeking to use another utility's ROW will reach agreement for the division of costs for the ROW before the ROW is shared. If the utilities are unable to reach an agreement, the Commission may determine the proportion of costs that each utility must bear in order to share the ratepayer funded ROW." (*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruing Inviting Comment on Phase 2 Issues*, February 5, 2024, at 19-20)

ROW sharing by incumbent public utilities may be subject to Public Utilities Code Section 851 or, if applicable, General Order 173. Specifically, pursuant to Public Utilities Code Section 851, a public utility "shall not sell, lease, assign, mortgage, or otherwise dispose of, or encumber the whole or any part of its line, plant, system, or other property necessary or useful in the performance of its duties to the public, or any franchise or permit or any right thereunder, or by any means whatsoever, directly or indirectly, merge or consolidate its line, plant, system, or other property, or franchises or permits or any part thereof" without first having either secured an order from the CPUC authorizing it to do so, or filed an advice letter and obtained approval from the CPUC authorizing it to do so.

3.6.2 Proposals

Proposal 1: Establish a ROW-Sharing Process for Incumbent and Non-Incumbent Utilities

This proposal would amend Section IX to create a new Section IX.D adopting a reformatted but substantively consistent version of the right-of-way-sharing language proposed by the California Public Advocates Office (Cal Advocates) in its opening comments on the December 18, 2023 ALJs' Ruling Inviting Comment on Phase 2 Issues. This new text would establish a requirement that incumbent and non-incumbent utilities must negotiate a joint use agreement that reflects their agreement on the fair compensation paid to the incumbent utility for the use of its ratepayer-funded ROWs. Specific modifications to Section IX would include establishing procedures to initiate the ROW sharing process as soon as a non-incumbent electric utility determines that it needs access to an incumbent electric utility's

ROW, and to enable the Commission to make an order determining reasonable ROW terms and fair compensation for use of the ROW in cases where the two utilities cannot reach an agreement.

The new Section IX.D would include the following text:

D. Right-of-Way Sharing Between Incumbent and Non-Incumbent Utilities

1. In the event that a non-incumbent utility needs to use an incumbent utility's right-of-way to construct an electrical transmission facility approved by the CAISO, the Commission may exercise its authority pursuant to Sections 762, 762.5, 767, 1001, and 1002 of the Public Utilities Code to require electric public utilities to establish an agreement for the joint use of the incumbent utility's ratepayer-funded right-of-way (joint use agreement). The joint use agreement shall establish reasonable compensation and reasonable terms and conditions by which the non-incumbent utility can use the incumbent utility's right-of-way to construct the electrical transmission facility for which the non-incumbent utility seeks a permit to construct or CPCN from the Commission.
    a. For the purposes of Section IX.D, a "non-incumbent utility" is a party seeking a permit to construct or CPCN from the Commission to construct an electrical transmission facility, and seeking to use another electric public utility's right-of-way to construct that facility.
    b. For the purposes of Section IX.D, an "incumbent utility" is a party that owns a right-of-way that a non-incumbent utility seeks to use to construct an electrical transmission facility.
2. Electric public utilities seeking to establish a joint use agreement pursuant to Section IX.D.1 shall comply with the following procedure:
    a. If a non-incumbent utility requests either a permit to construct or a CPCN for an electrical transmission facility approved by the CAISO, and needs access to another incumbent party's right-of-way to build the project, the non-incumbent utility shall promptly follow the procedure set forth in Public Utilities Code Section 705 or a procedure set forth by an administrative law judge that comports with Section 705 and request that the Commission hold a hearing pursuant to Public Utilities Code Section 762 or 767.
    b. Prior to the hearing, the non-incumbent utility and incumbent utility shall meet and confer and bargain in good faith to establish a joint use agreement. Not less than 10 days prior to the hearing, the incumbent utility and non-incumbent utility shall file and serve a joint statement that confirms both parties have met and conferred, and lists all issues of material fact related to the requested joint use agreement, and identifies those issues on that the incumbent utility and non-incumbent utility were unable to resolve, if any.
    c. The Commission shall fix a reasonable time that will not delay the permit to construct or CPCN proceeding, and within which the non-incumbent utility and

incumbent utility shall agree to reasonable terms and conditions for joint use of the right-of-way.

d. If, at the expiration of such time, the incumbent utility and non-incumbent utility fail to file with the Commission a statement that an agreement has been made for joint use of the incumbent utility's right-of-way, including the reasonable division of costs and reasonable terms and conditions, the Commission may, after further hearing, make an order fixing the proportion of cost and terms and conditions for joint use of the right-of-way.

e. In the event a further hearing is necessary, 10 days prior to the further hearing, the incumbent utility and non-incumbent utility shall file and serve a joint statement that includes any new issues of material fact that were not raised prior to the first hearing and the reasons why the new issues of material fact could not have been raised prior to the first hearing. The Commission would limit the second hearing to issues of material fact that could not have been addressed in the first hearing.

Staff recommend further consideration of Proposal 1, whether in a third phase of the R.23-05-018 proceeding or in a separate proceeding. Staff recognize the benefits to ratepayers, communities, and the environment that are associated with ROW-sharing between incumbent and non-incumbent utilities, but acknowledge that this proposal would benefit from additional development via one or more workshops involving incumbent and non-incumbent utilities, among other parties. In particular, the concerns raised by the large IOUs in reply comments to the ALJs' Ruling Inviting Comment on Phase 2 Issues should be addressed before this proposal (or a modified version thereof) is adopted. The rationale for the staff recommendation is provided in Section 3.6.4 below.

3.6.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1: Staff recommend further consideration of Proposal 1, whether in a third phase of the R.23-05-018 proceeding or in a separate proceeding. Staff recognize the benefits to ratepayers, communities, and the environment that are associated with ROW-sharing between incumbent and non-incumbent utilities, but acknowledge that this proposal would benefit from additional development via one or more workshops involving incumbent and non-incumbent utilities, among other parties. In particular, the concerns raised by the large IOUs in reply comments to the ALJs' Ruling Inviting Comment on Phase 2 Issues should be addressed before this proposal (or a modified version thereof) is adopted. The rationale for the staff recommendation is provided in Section 3.6.4 below.

3.6.4 Rationale for Staff Recommendations

Staff recommend further consideration of Proposal 1 for the following reasons:

- **A range of parties expressed support for further development of the Cal Advocates proposal, asserting that exploring mechanisms to facilitate ROW sharing could reduce project costs, streamline project construction, and result in environmental benefits.** Although some parties have expressed opposition to adopting the Cal Advocates proposal in its current form in the R.23-05-018 Phase 2 decision, a range of other parties have expressed support for exploring options to facilitate ROW sharing between incumbent and non-incumbent utilities.
    - American Clean Power asserts, "Cal Advocates' Right-of-Way proposal would facilitate third-party transmission development by creating more rights for transmission developers to use existing rights-of-way, much of which are on already-disturbed lands. Typically, brown-field projects are able to complete [CEQA] review in a timelier fashion than permitting on undisturbed lands. Thus, the right-of-way proposal could help facilitate faster permitting timelines, as well as overall cost-efficiencies for network-upgrade development. As the volume of network upgrades needed to meet the State's clean energy targets continues to grow, we believe that merchant transmission developers will need to play a more prominent role in developing policy-driven upgrades. A right-of-way sharing proposal could better enable project developers and CAISO to consider lowest cost options in selecting winners of competitive solicitations. We therefore support ongoing consideration of this issue following the Commission's review of the settlement agreement." (*American Clean Power – California Reply Comments on Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 2)
    - LS Power asserts, "LSPGC sees strong merit in the policy and the substance of the PAO's proposal for sharing of utility's rights of way. … Assembling the necessary land rights presents a major hurdle and barrier to entry for the development of a new transmission project. Use of the existing utility rights of way, with fair compensation and reasonable terms and conditions, by winning bidders in the CAISO competitive transmission bidding processes will provide several benefits for California electricity customers without interfering with the utility's operations." (*Reply Comments of LS Power Grid California, LLC (U-247-E) on Phase 2 Issues*, February 26, 2024, at 8)
    - LS Power further asserts, "Allowing non-incumbent transmission developers to access utility rights of way and other property offers several benefits to ratepayers … If all competitors have access to the utility rights of way and other property, the competition will focus on the cost of constructing the project, and all competitors (including the incumbent utility) will be subject to competitive pressure to reduce construction costs as much as possible. Reduced costs for the project will translate into lower rates." (*Reply Comments of LS Power Grid California, LLC (U-247-E) on Phase 2 Issues*, February 26, 2024, at 20) LS Power further asserts, "The CAISO also approves projects that are justified as economic transmission solutions that reduce congestion and lower the cost of providing electricity to California consumers. Reducing the costs of constructing those projects will result in even greater cost reductions for electricity and lower rates for electric consumers in California." (*Reply Comments of LS Power Grid California, LLC (U-247-E) on Phase 2 Issues*, February 26, 2024, at 21)

  - LS Power further asserts that exploring mechanisms to facilitate ROW sharing could help minimize the environmental impacts of proposed electrical transmission projects: "Joint use of utility rights of way will also reduce the environmental impacts of new transmission by making use of land that is already set aside for transmission purposes and by avoiding disturbing additional acreage outside of the right of way." (*Reply Comments of LS Power Grid California, LLC (U-247-E) on Phase 2 Issues*, February 26, 2024, at 9) LS Power further asserts, "If non-incumbent transmission developers can use existing rights of way or other property and are not required to secure a separate right of way for a transmission project, land use and related environmental impacts will be minimized." (*Reply Comments of LS Power Grid California, LLC (U-247-E) on Phase 2 Issues*, February 26, 2024, at 20)
  - The Acton Town Council expresses support for the Cal Advocates ROW-sharing proposal and suggests that one or more workshops be convened to further develop the proposal with input from Energy Division staff: "The Acton Town Council believes that the bold, crosscutting recommendations which CalAdvocates proposes would be best initiated via one or more workshops which will facilitate collaboration and encourage dialogue among parties that have differing perspectives. The opportunities for dynamic interactions that are created by workshop events often provide superior results compared to static "review and comment" processes, particularly in the development of new programs. Accordingly, we suggest that one or more workshops be convened to "flesh out" CalAdvocates proposals. We also recommend that Energy Division staff participate in these workshops because they have considerable expertise in the strengths and flaws of the Commission's existing permit process." (*Reply Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 60)
  - The Independent Energy Producers Association states, "Cal Advocates' second proposal addresses the potential benefits of requiring utilities to share their existing rights-of-way with non-incumbent transmission utilities. Cal Advocates' proposal is particularly relevant in the context of the CAISO's competitive solicitations for regional transmission projects, where access to rights-of-way is a key selection factor that works to the disadvantage of non-incumbent transmission utilities. Cal Advocates' proposal could result in cost savings for some significant transmission projects. This proposal deserves the Commission's further consideration." (*Reply Comments of the Independent Energy Producers Association on Phase 2 Issues*, February 26, 2024, at 10)
  - Cal Advocates asserts, "ROW sharing can reduce project costs and streamline project construction because it would enable non-incumbent electric utilities to: 1) build on already-permitted land; 2) use already-constructed assets; and 3) locate construction on land parcels that have already undergone some form of environmental review." (*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruing Inviting Comment on Phase 2 Issues*, February 5, 2024, at 16)
- **IOUs (i.e., incumbent utilities) expressed extensive opposition to the Cal Advocates ROW-sharing proposal, suggesting that the ideas therein would benefit from further development and stakeholder input.** Among other concerns, the IOUs assert that allowing another utility to

build transmission lines in the easement holder's ROW could extend beyond what many landowners have negotiated with the incumbent utility, and that in such a situation, the incumbent might violate the terms of such easements and subject itself to unnecessary litigation and higher rates for its ratepayers if it were to apportion a part of its rights to a third party. The extensive concerns raised by incumbent utilities in response to this proposal merit further consideration, potentially in a separate proceeding and/or through one more ore party workshops, to determine if a modified version of the Cal Advocates proposal could address these issues.

- SCE asserts, "Several critical issues likely to be of great concern to property owners and utilities alike are completely unaddressed in Cal Advocates' proposal, such as: 1) how to ensure that responsibility for maintaining the easement area and protecting property would be allocated given that multiple parties would have infrastructure in the easement area; 2) how to ensure that the multiple parties, each likely requiring separate access rights, would not be overburdening the easement with simultaneous overlapping activity; and 3) points of contact between the landowner and the multiple utilities, unlike typical easement situations." (*Southern California Edison Company's (U 338-E) Reply Comments on the Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 30)
- SCE asserts that apportioning franchise rights would potentially deprive the granting jurisdiction of revenue and prevent it from being adequately protected: "Apportioning franchises to multiple utilities would deprive local jurisdictions of franchise revenue that otherwise would be recovered from multiple utilities if each were to seek their own franchise rights from the jurisdiction. Further, apportioning franchise rights would potentially deprive the granting jurisdiction of revenue and prevent it from being adequately protected. … But if an incumbent utility franchise-holder were forced to give up some of its franchise rights, how would that be communicated, much less legally established with compensation allocated, with the local jurisdiction? The ROW Sharing Proposal does not indicate whether Cal Advocates suggests that each affected jurisdiction should be required to enter into a separate franchise agreement with the non-incumbent utility (presuming such separate agreement were even allowed under The Franchise Act of 1937). Nor does the proposal provide any insight into how the local jurisdiction might be able to safeguard its public property." (*Southern California Edison Company's (U 338-E) Reply Comments on the Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 31-32)
- SDG&E asserts, "The Commission should reject PAO's proposal related to right-of-way ("ROW") sharing, which in fact also proposes to "share" fee-owned property." (*Reply Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 26, 2024, at 45)
- SDG&E further asserts that the Cal Advocates ROW-sharing proposal could result in delays and added costs to IOUs' reliability and safety projects: "Finally, PAO's ROW sharing proposal could well cause significant disruption, delays and added cost. When SDG&E (and presumably other public utilities) acquires ROW or fee-owned property, it does so when feasible with an eye toward the future needs to expand its electric system to provide reliable electric service to its customers. If a third party utility was granted space in SDG&E ROW

or on fee-owned substation property for its purposes, such space would not be available for future SDG&E use. Instead, SDG&E, rather than a third party, would be forced to identify potential new property and either negotiate or condemn necessary land rights. This could result in delays and added costs to SDG&E's needed reliability and safety projects. In other words, by giving third parties the benefit of SDG&E's prudent, future-oriented investments, PAO's proposal simply pushes the acquisition of land rights to the future, when costs may be significantly higher or adjacent land no longer available. PAO's proposal to take utilities' land rights and give them to third parties should be rejected." (*Reply Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 26, 2024, at 49-50)

- PG&E asserts, "PAO points to joint use agreements used by telecommunication providers as a model for its proposal, but the comparison is misplaced. The telecommunications decisions refer to joint use of poles for which PG&E issues a revocable license to the carrier under General Order 69-C.48 While PAO's Reply refers repeatedly to "joint use," there is no way that placing a "non-incumbent" utility's substation on another utility's property could be "joint use" of that substation space." (*Reply Comments of Pacific Gas and Electric Company (U 39-E) on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 12)

- **PG&E, SCE, and SDG&E assert that Public Utilities Code Section 767 does not support the Cal Advocates ROW-sharing proposal. The record on this matter should be further developed.**
  - SCE asserts, "Cal Advocates relies largely on Public Utilities Code section 767. But Section 767 does not go as far as Cal Advocates' proposal. First, Public Utilities Code section 767 does not authorize the Commission to "direct one utility company to share any part of its property or equipment with another public utility" as Cal Advocates suggests. Rather, the scope of Section 767 authority is textually limited to "conduits, subways, tracks, wires, poles, ducts, or other equipment, on, over, or under any street or highway…." Thus, while the Commission may have authority to, in certain, circumstances, obligate a utility company to share utility facilities existing in the public right-of-way, by its text Section 767 goes no further." (*Southern California Edison Company's (U 338-E) Reply Comments on the Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 34)
  - PG&E claims that Public Utilities Code Section 767 does not support the Cal Advocates proposal: "Contrary to PAO's claims, PUC Section 767 does not in any way support this forced transfer of utility assets. Rather, similar to the telecommunication decisions, it establishes a system for one utility to use the existing "conduits, subways, tracks, wires, poles, pipes, or other equipment, on, over, or under any street or highway" of another utility "only when such use will not result in irreparable injury to the owner or other users of such property or equipment or in any substantial detriment to the service." Section 767 does not allow for a utility to use another utility's currently unused easements or substation properties, but instead focuses on the joint use of existing poles or other equipment. Even then, joint use is not allowed when the owner of the property right will suffer "irreparable injury" or a "substantial detriment" to the service, both of which would occur by building a new

substation on property preserved by another utility for substation expansion and other uses." (*Reply Comments of Pacific Gas and Electric Company (U 39-E) on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 14)

- SDG&E asserts, "Further, SDG&E disagrees with PAO's expansive interpretation of the Public Utilities Code. In particular, PAO's understanding of Section 767 is simply wrong. Public Utilities Code Section 767 only allows for one utility to use the existing "conduits, subways, tracks, wires, poles, pipes, or other equipment, on, over, or under any street or highway" of another utility "and only when such use will not result in irreparable injury to the owner or other users of such property or equipment or in any substantial detriment to the service.142 Section 767 does not allow for a utility to use another utility's currently unused ROW (or fee-owned property) and is instead focused on the joint use of existing infrastructure (i.e. equipment) "on, over, or under any street or highway." Additionally, having SDG&E ROW or fee-owned property seized and used by another entity would necessarily cause an irreparable injury in violation of Section 767 both to (a) the owner of the land subject to a ROW easement, who did not agree to such use, and (b) SDG&E, which would lose the ability to use any "taken" ROW or fee-owned property to meet the needs of its customers in the future." (*Reply Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 26, 2024, at 46-47)

- **Several parties have suggested that the Cal Advocates ROW-sharing proposal may be more appropriately addressed in a separate proceeding.**
  - PG&E states, "This proposal is problematic on so many levels that, if the Commission wishes to pursue it, a separate proceeding is essential to fully assess the consequences." (*Reply Comments of Pacific Gas and Electric Company (U 39-E) on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 14)
  - SDG&E asserts, "The Order Instituting Rulemaking initiating this proceeding made it clear the Commission's goal "is to adopt a new 'E' version of GO 131 that will better address the needs of the State of California and its residents, be consistent with SB 529, other applicable laws, policies and Federal Energy Regulatory Commission (FERC) orders, and provide a clearer, more efficient and consistent process." The July 31, 2023 Assigned Commissioner's Scoping Memo And Ruling ("Scoping Memo") set a similar scope for the proceeding. PAO's proposal to take electric public utilities' property rights and give them to third party developers is not within that scope, going well beyond the subject matter covered by GO-131-D, which focuses on the process/requirements for CPCNs, PTCs, and related reporting." (*Reply Comments of San Diego Gas & Electric Company (U 902 E) on Phase 2 Issues*, February 26, 2024, at 45-46)

3.7 Accelerate the CPCN and PTC Application Process

3.7.1 Problem Statement

In 2023, the California Public Advocates Office (Cal Advocates) analyzed the development timelines of 14 recently approved and completed electrical transmission projects, and found that the pre-application planning phase took 2.4 years on average for larger projects (200 kV or more) subject to the CPCN process, and took four years on average for smaller projects (50 to 200 kV) subject to the PTC process. The resulting memo stated, "One observation is that developers invest long times in the pre-application planning stage prior to undertaking CPUC's formal permitting process. In fact, pre-application planning is one of the primary contributors to the overall transmission development timeline, particularly for smaller projects." (Cal Advocates, Transmission Project Development Timelines in California, June 12, 2023, at 3)

Sections VIII and IX.A of GO 131-D outline the application process for CPCNs, while Section IX.B outlines the application process for PTCs. GO 131-D states that electric public utilities shall file a CPCN application "not less than 12 months prior to the date of a required decision by the Commission" and a PTC application "not less than nine (9) months prior to the date of a required decision by the Commission" unless the CPUC authorizes a shorter period. Once a utility has filed an application, CPUC staff must review it and notify the utility in writing of any deficiencies within 30 days, as required by Government Code Section 65943. The utility must then correct any deficiencies within 60 days (for a CPCN application) or 30 days (for a PTC application), or explain in writing why it is unable to do so. In some cases, multiple deficiency letters and multiple rounds of revisions are necessary to correct the deficiencies (and/or any new deficiencies that may result from the corrections) before CPUC staff can deem an application complete.[13] Once the application is deemed complete pending correction of any deficiencies, CPUC staff must determine whether CEQA applies, and if so, whether an EIR or MND/ND has been or will be prepared.

Applications for CPCNs must comply with the Commission's Rules of Practice and Procedure and must include a range of information listed in GO 131-D Sections VIII and IX.A.1, including a detailed description of proposed facilities; a proposed schedule; a map; a statement of why the public convenience and necessity require the construction of the project; a detailed statement of the estimated cost of the project; routing alternatives; a list of required permits; and a summary of consultation with public agencies. Pursuant to Section IX.B.1, applications for PTCs must include most of the same information required for CPCNs, except that PTC applications need not include a detailed analysis of purpose and need, a detailed estimate of cost and economic analysis, a detailed schedule, or a detailed description of construction methods beyond that required for CEQA compliance.

In addition to the application requirements listed in Sections VIII and IX, Section X, Potential Exposure to Electric and Magnetic Fields (EMFs), requires CPCN and PTC applications to include a discussion of measures taken or proposed by the applicant to reduce the potential exposure to EMFs generated by the proposed facilities. In the version of GO 131-D adopted in 1995, Section X was bifurcated into two

[13] The foreword to the Commission's PEA Guidelines states, "Our staff have reviewed the timelines for 108 past CPUC applications that required review pursuant to CEQA and determined that the average length of time from application filing to PEA deemed complete is four months, regardless of the type of CEQA document. The goal for our agency is to deem PEAs complete within 30 days." (*Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments*, Version 1.0, November 2019, at ii)

subsections: Section X.A and Section X.B. Section X.B made reference to an Electric and Magnetic Fields (EMF) education program which ended on March 1, 1999, stating, "The EMF education program administered by the California Department of Health Services for regulated electric utility facilities, established in Investigation (I.) 9 l-01-012, is available to provide independent information about EMF to local government, other state agencies, and the public to assist in their consideration of the potential impacts of facilities proposed by electric utilities hereunder. Local government and the public should first contact their public health department." The Decision Addressing Phase 1 Issues (D.23-12-035) deleted Section X.B, leaving only a brief paragraph (formerly Section X.A) requiring that CPCN and PTC applications "shall describe the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields generated by the proposed facilities, in compliance with Commission order".

Although the text of GO 131-D (Sections IX.A.1.h and IX.B.1.e) refers to the PEA as an optional application component (i.e., allowing submittal of "A PEA or equivalent information"), Rule 2.4(b) of the Commission's Rules of Practice and Procedure requires that any application for a CEQA project shall include a PEA prepared in accordance with the Commission's Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments (Version 1.0, November 2019), which includes a PEA Checklist and Pre-filing Consultation Guidelines.

> (b) Any application for authority to undertake a project that is not statutorily or categorically exempt from CEQA requirements shall include a Proponent's Environmental Assessment (PEA). The PEA shall include all information and studies required under the Commission's Information and Criteria List adopted pursuant to Chapter 1200 of the Statutes of 1977 (Government Code Sections 65940 through 65942), which is published on the Commission's Internet website. If the proposed project is an energy infrastructure project, the applicant shall prepare the PEA in accordance with the Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments (Version 1.0, November 2019) which is published on the Commission's Internet website and is hereby incorporated by reference. (CPUC Rules of Practice and Procedure, Rule 2.4; California Code of Regulations, Title 20, Division 1, Chapter 1; May 2021)

The PEA Checklist is the outline required for all PEAs, and includes each of the chapters and sections found in typical CPUC EIRs. The Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments (Version 1.0, November 2019) state, "PEAs will include each chapter and section identified (in matching numerical order) unless otherwise directed by CPUC CEQA Unit Staff in writing prior to filing."

6. **PEA Organization:** This PEA Checklist is organized to include each of the chapters and sections found in typical CPUC EIRs. The following sections will serve as the outline for all Draft PEAs submitted during Pre-filing and all PEAs filed with the CPUC Docket Office. PEAs will include each chapter and section identified (in matching numerical order) unless otherwise directed by CPUC CEQA Unit Staff in writing prior to filing.

In the Joint Motion for Adoption of Phase 1 Settlement Agreement, the settling parties propose modifying Section VIII.A.7 and IX.C.1 of GO 131-D to explicitly enable applicants to submit a draft CEQA document in lieu of a PEA. The settling parties' suggested amendments are included below as Proposal 1, Option 1.

3.7.2 Proposals

Proposal 1: Enable Applicant-Submitted Draft CEQA Documents

This proposal would amend Sections VIII and IX to explicitly enable applicants to submit a draft version of a CEQA document instead of a PEA. **Option 1** is the proposal submitted by settling parties in the Joint Motion for Adoption of Phase 1 Settlement Agreement on September 29, 2023, while **Option 2** and **Option 3** represent staff recommendations to modify components of the settling parties' proposal for consistency with CEQA and the Commission's existing policies.

Option 1: Adopt the revisions to Sections VIII.A.7 and IX.C.1 proposed by settling parties in the Joint Motion for Adoption of Phase 1 Settlement Agreement to explicitly enable applicants to submit a draft CEQA document in lieu of a PEA. In addition to the proposed modifications to GO 131-D, implementing this proposal would necessitate the creation of a list of application requirements pursuant to Government Code Section 65940, and may require commensurate changes to the Commission's Rules of Practice and Procedure and to the Commission's Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments (Version 1.0, November 2019), as described below.

Section VIII.A.7 would be modified as follows, with new text underlined in red:

7. A Proponent's Environment Assessment (PEA) on the environmental impact of the proposed facility and its operation so as to permit compliance with the requirements of CEQA and this Commission's Rules of Practice and Procedure 2.4 and 2.5. If a PEA is filed, it may include the data described in Items 1 through 6, above. Notwithstanding the foregoing, an applicant may elect to prepare and submit with its application, in lieu of a PEA, a draft environmental impact report, draft mitigated negative declaration, draft negative declaration, draft addendum, or analysis of the applicability of an exemption from CEQA (each a CEQA Document). Energy Division may provide the applicant with appropriate guidance and assist in the preparation of the draft CEQA Document. Before using a draft CEQA Document prepared by the applicant, the Commission shall subject the draft to its independent review and analysis. Any draft CEQA Document sent out for public review shall reflect the independent judgment of the Commission.

Section IX would be modified to include a new Section IX.C and IX.C.1 regarding the preparation of CEQA documents. The text of Section IX.C and IX.C.1 would read as follows:

C. Preparation of CEQA Documents and Commission Decision

1. Notwithstanding any other provision herein, an applicant may elect to prepare and submit with its application, in lieu of the Proponent's Environmental Assessment required by Rule of Practice and Procedure 2.4, a draft environmental impact report, draft mitigated negative

> declaration, draft negative declaration, draft addendum, or analysis of the applicability of an exemption from CEQA (each a CEQA Document). Energy Division may provide the applicant with appropriate guidance and assist in the preparation of the draft CEQA Document. Before using a draft CEQA Document prepared by the applicant, the Commission shall subject the draft to its independent review and analysis. Any draft CEQA Document sent out for public review shall reflect the independent judgment of the Commission.

Implementing the settling parties' proposed modifications to GO 131-D Sections VIII.A.7 and IX may necessitate conforming changes to the Commission's Rules of Practice and Procedure and PEA Guidelines. The PEA Guidelines contain a PEA Checklist table of required chapters and sections which must be included in each PEA in matching numerical order.

Rule 2.4(b) of the Rules of Practice and Procedure requires that any application for a CEQA project include a PEA prepared in accordance with the PEA Guidelines. Modifying GO 131-D to develop an in-lieu process for applicant-prepared draft CEQA documents would be inconsistent with the existing language of Rule 2.4(b), and could necessitate modifying Rule 2.4(b) to reference the in-lieu process. However, the Commission could conceivably deem complete any applications containing an applicant-prepared draft CEQA document prior to the modification of the Rules of Practice and Procedure.

The Commission's PEA Guidelines may need to be modified to remove existing references to the applicant-prepared PEA being a required component of energy project applications. For instance, the Foreword to the Guidelines states, "The CPUC's Rules of Practice and Procedure Sections 2.4 provide that all applications to the CPUC for authority to undertake projects that are not statutorily or categorically exempt from CEQA requirements shall include an Applicant-prepared PEA." (Foreword to the Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments, November 12, 2019, at i). Modifying the PEA Guidelines would in turn require a commensurate update to Rule 2.4, which currently refers to Version 1.0, November 2019 of the PEA Guidelines.

Additionally, in order to implement the alternative application process proposed by the settling parties, the Commission would need to establish one or more lists that specify in detail the information that is required from any applicant for a development project, pursuant to Government Code Section 65940. The PEA Guidelines currently specify the Commission's required application information. If the applicant-prepared draft CEQA document is not required to include the information in the PEA Guidelines, then the Commission may need to establish a separate list (or lists) detailing the application requirements not already included in Section VIII and IX of GO 131-D. Proposal 1, Option 3 outlines a potential list of criteria that would apply to applicant-prepared CEQA documents.

Modifying the Commission's Rules of Practice and Procedure and/or the Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments would necessitate review by the California Office of Administrative Law (OAL), which is responsible for reviewing administrative regulations proposed by state agencies to ensure that they are compliant with the standards in the Administrative Procedure Act (APA) and are clear, necessary, legally valid, and available to the public. The OAL process could constitute a lengthy addition to the process of implementing this proposal.

Option 2: Adopt a modified version of the settling parties' proposed revisions to Sections VIII and IX outlined in Proposal 1, Option 1. This modified version would explicitly enable applicants to prepare and submit a draft version of an initial study or EIR in lieu of a PEA, provided that the draft CEQA document meets the specifications of the CPUC's PEA Guidelines, and that the applicant first initiates pre-filing consultation with Commission staff at least 12 months prior to the filing of the application and provides the draft CEQA document(s) during pre-filing.

In addition to the proposed modifications to GO 131-D, implementing this proposal may require conforming changes to the Commission's Rules of Practice and Procedure and PEA Guidelines, as described in Proposal 1, Option 1. However, in contrast to Option 1, requiring applicant-prepared draft CEQA documents to contain the required contents of the Commission's PEA Guidelines may not require the Commission to develop a separate list of application requirements pursuant to Government Code Section 65940.

Section VIII would be modified to include a new Section VIII.B, the text of which would read as follows:

B. An applicant may elect to prepare and submit a draft version of an initial study or a draft version of an EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project provided that 1) the document includes an appendix containing any of the required contents outlined in the Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments that are not addressed in the body of the draft CEQA document; 2) the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing; and 3) the applicant provides the draft documents to Energy Division staff for review during the pre-filing period. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis. Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

The existing Section VIII.B in the current version of GO 131-D would be split into Sections VIII.C, VIII.D, and VIII.E.

Section IX.B.8 (formerly IX.B.4) would be modified as follows, with new text underlined in red and deleted text in red strikethrough:

8. If the Energy Division determines, after ~~completing its~~ the completion of an initial study, that the project would not have a significant adverse impact on the environment, the Energy Division will ~~a Negative Declaration~~ an ND. If the initial study identifies potential significant effects, but the utility revises its proposal to avoid those effects, then the Commission could adopt ~~a Mitigated Negative Declaration~~ an MND. In either case, the Commission will grant the ~~permit to construct~~ PTC.

Section IX would be modified to include a new Section IX.C and IX.C.1 regarding the preparation of CEQA documents. The text of Section IX.C and IX.C.1 would read as follows:

C. Preparation of CEQA Documents and Commission Decision

1. An applicant may elect to prepare and submit a draft version of an initial study or a draft version of an EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project provided that 1) the document includes an appendix containing any of the required contents outlined in the Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments that are not addressed in the body of the draft CEQA document; 2) the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing; and 3) the applicant provides the draft documents to Energy Division staff for review during the pre-filing period. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis. Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

These modifications to the settling parties' proposal would provide applicants a clear pathway to file a draft version of a CEQA document in lieu of the existing PEA requirement, but would also provide a more implementable process that is consistent with CEQA and the policies of the Commission.

Requiring applicants to initiate pre-filing consultation with the Energy Division not less than 12 months prior to submitting a draft version of a CEQA document would enable Energy Division staff and consultants to provide input on the format and content of the draft CEQA document (e.g., whether an EIR is required versus an MND) via meetings and preliminary review in the early stages of development rather than waiting to refine the approach in the application review process via deficiency letters. Proactive early pre-filing consultation with the Energy Division increases the likelihood that a draft document will be consistent with the needs of the Commission.

Requiring applicant-submitted draft versions of initial studies or EIRs to include the contents of the PEA Guidelines would allow applicants to choose to prepare a draft version of a CEQA document in lieu of a PEA while still providing Energy Division staff and consultants the necessary information to process the application and prepare the draft CEQA document for public circulation. The PEA Checklist functions as a list "that [specifies] in detail the information that is required from any applicant for a development project", pursuant to Government Code Section 65940.

Limiting the types of applicant-prepared draft CEQA document to an initial study or an EIR (rather than a draft EIR, MND, ND, addendum, or analysis of the applicability of an exemption from CEQA, as proposed by the settling parties) would be consistent with CEQA Guidelines Section 15063(c)—which states that the first purpose of an initial study is to "Provide the Lead Agency with information to use as the basis for deciding whether to prepare an EIR or a Negative Declaration"—and Section 15063(a), which states that "If the Lead Agency can determine that an EIR will clearly be required for the project, an Initial Study is not required but may still be desirable." The "initial study" is the technical term used for the draft initial study/mitigated negative declaration (IS/MND) or initial study/negative declaration (IS/ND) prior to the circulation of a draft to the public. Once the Energy Division circulated the draft initial study to the public (with or without additional revisions to the applicant-submitted version), the document would be referred to as either an IS/MND or IS/ND. Adopting this technical change to the settling parties' proposal would better reflect with the CEQA Guidelines and would make clear the nuance that Energy Division staff—not the applicant—would ultimately be responsible for circulating the draft document to the public.

Staff recommend that the Commission adopt either Option 2 or Option 3. The rationale for staff's recommendation is provided in Section 3.7.4 below.

Option 3: Adopt a modified version of the settling parties' proposed revisions to Sections VIII and IX outlined in Proposal 1, Option 1. This modified version would explicitly enable applicants to prepare and submit a draft version of an initial study or EIR in lieu of a PEA, provided that the applicant first initiates pre-filing consultation with Commission staff at least 12 months prior to the filing of the application, provides the draft CEQA document(s) during pre-filing, and complies with other applicable Commission policies. In contrast to Proposal 1, Option 2, this option would not require the applicant-prepared draft CEQA document to meet the specifications of the CPUC's PEA Guidelines.

In addition to the proposed modifications to GO 131-D, implementing this proposal may require conforming changes to the Commission's Rules of Practice and Procedure, as described in Proposal 1, Option 1 and Proposal 1, Option 2. However, in contrast to Option 1 and Option 2, this option would insert additional application criteria directly into the text of GO 131 to ensure that the application requirements are compliant with Government Code Section 65940.

A new Section VIII.A.8 (unless Section 3.7.2, Proposal 2 is not adopted, in which case the new section proposed here would be VIII.A.7) would be added to Section VIII.A establishing that a CPCN application must include or have attached to it a demonstration of compliance with other applicable CPUC policies, as follows:

8. Demonstration of compliance with other applicable Commission policies (e.g., the Environmental and Social Justice [ESJ] Action Plan).

Section VIII would be modified to include a new Section VIII.B, the text of which would read as follows:

B. An applicant may prepare and submit a draft version of an initial study or EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project if the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing, and provides the draft documents to Energy Division staff for review during the pre-filing period.

1. An applicant-prepared version of a draft CEQA document shall comply with the CEQA Guidelines, shall provide substantial evidence for all findings and conclusions, and shall include issue-specific technical studies (e.g., biological resource studies, cultural resource studies).
2. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis. Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

The existing Section VIII.B in the current version of GO 131-D would be split into Sections VIII.C, VIII.D, and VIII.E.

Section IX.A.2 (formerly IX.A.1) would be modified to include a new section IX.A.2.i (unless Section 3.7.2, Proposal 2 is not adopted, in which case the new section proposed here would be IX.A.2.h) establishing that a CPCN application must include or have attached to it a demonstration of compliance with other applicable CPUC policies, as follows:

i. Demonstration of compliance with other applicable Commission policies (e.g., the ESJ Action Plan).

Section IX.B.2 (formerly IX.B.1) would be modified to include a new section IX.B.2.f (unless Section 3.7.2, Proposal 2 is not adopted, in which case the new section proposed here would be IX.B.2.e) establishing that a PTC application must include or have attached to it a demonstration of compliance with other applicable CPUC policies, as follows:

f. Demonstration of compliance with other applicable Commission policies (e.g., the ESJ Action Plan).

Section IX.B.8 (formerly IX.B.4) would be modified as follows, with new text underlined in red and deleted text in red strikethrough:

8. If the Energy Division determines, after ~~completing its~~ the completion of an initial study, that the project would not have a significant adverse impact on the environment, the Energy Division will prepare ~~a Negative Declaration~~ an ND. If the initial study identifies potential significant effects, but the utility revises its proposal to avoid those effects, then the Commission could adopt ~~a Mitigated Negative Declaration~~ an MND. In either case, the Commission will grant the ~~permit to construct~~ PTC.

Section IX would be modified to include a new Section IX.C and IX.C.1 regarding the preparation of CEQA documents. The text of Section IX.C and IX.C.1 would read as follows:

C. Preparation of CEQA Documents and Commission Decision

1. An applicant may elect to prepare and submit a draft version of an initial study or a draft version of an EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project provided that the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing, and provides the draft documents to Energy Division staff for review during the pre-filing period.

   a. An applicant-prepared version of a draft CEQA document shall comply with the CEQA Guidelines, shall provide substantial evidence for all findings and conclusions, and shall include issue-specific technical studies (e.g., biological resource studies, cultural resource studies).

   b. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis. Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

Staff recommend that the Commission adopt Option 3. The rationale for the staff recommendation is provided in Section 3.7.4 below.

Proposal 2: Consolidate EMF Requirements

This proposal would consolidate the application requirements listed in GO 131-D by deleting Section X and incorporating the EMF requirements into the existing lists of CPCN and PTC application requirements provided in Sections VIII.A, IX.A.1, and IX.B.1.

Section VIII would be modified to include a new Section VIII.A.7 containing the EMF requirements. The numbering of subsequent sections would be updated accordingly. The modified text of Section VIII.A would read as follows, with new additions underlined in red:

7. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

Section IX.A.1 would be modified to include a new Section IX.B.1.e containing the EMF requirements. The numbering of subsequent sections would be updated accordingly. The modified text of Section IX.A.1 would read as follows, with new additions underlined in red:

h. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

Section IX.B.1 would be modified to include a new Section IX.B.1.e containing the EMF requirements. The numbering of subsequent sections would be updated accordingly. The modified text of Section IX.B.1 would read as follows, with new additions underlined in red:

e. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

Section X would be deleted in its entirety, as shown in red strikethrough below.

> **~~SECTION X. POTENTIAL EXPOSURE TO ELECTRIC AND MAGNETIC FIELDS (EMF)~~**
>
> ~~Applications for a CPCN or Permit to Construct shall describe the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields generated by the proposed facilities, in compliance with Commission order. This information may be included in the PEA required by Rule 2.4 of the Commission's Rules of Practice and Procedure.~~

The numbering of all subsequent sections would be adjusted to reflect the deletion of the existing Section X such that the existing Section XI would become Section X, the existing Section XII would become Section XI, and so forth. Additionally, all existing references to the current Section X in GO 131-D would be deleted (e.g., where Section X is mentioned in Section III.B).

Staff recommend adoption of Proposal 2. The rationale for the staff recommendation is provided in Section 3.7.4 below.

Proposal 3: Require Pre-Filing Consultation

This proposal would modify Section IX.A and IX.B to require utilities to initiate pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than six months prior to the filing of a CPCN or PTC application.

Section IX.A would be modified as follows, with new text underlined in red:

A. Transmission Line Facilities of 200 kV and Over

1. An electric public utility desiring to build transmission line facilities in this state for immediate or eventual operation at or above 200 kV that require a CPCN under Section III.A, above, shall:

   a. ~~f~~File an application for a CPCN not less than 12 months prior to the date of a required decision by the Commission unless the Commission authorizes a shorter period because of exceptional circumstances~~.~~;

   b. Provide written notice to Energy Division staff not less than 12 months prior to the filing of a CPCN application; and

   c. Initiate pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than six (6) months prior to the filing of a CPCN application unless Energy Division staff authorize a shorter period in writing.

Section IX.B would be modified as follows, with new text underlined in red:

B. Transmission Line, Power Line, and Substation Facilities Designed to Operate Over 50 kV Which Are Not Included in Subsection A of this Section

1. Unless ~~exempt as specified in Section III herein, or~~ already included in an application before this Commission for a CPCN, an electric public utility desiring to build transmission line, power line, or substation facilities in this state for immediate or eventual operation over 50 kV, that require a ~~permit to construct~~ PTC under Section III.B, above, shall:

   a. ~~f~~File an application for a ~~permit to construct~~ PTC not less than nine (9) months prior to the date of a required decision by the Commission;

   b. Provide written notice to Energy Division staff not less than 12 months prior to the filing of a PTC application; and

   c. Initiate pre-filing consultation with Energy Division staff pursuant to Section IX.B.1 not less than six (6) months prior to the filing of a PTC application unless ~~the Commission~~ Energy Division staff authorize~~s~~ a shorter period ~~because of exceptional circumstances~~ in writing.

Staff recommend adoption of Proposal 3. The rationale for the staff recommendation is provided in Section 3.7.4 below.

3.7.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1, Option 3: Staff recommend adopting Proposal 1, Option 3. The rationale for the staff recommendation is provided in Section 3.7.4 below.

Proposal 2: Staff recommend adopting Proposal 2. The rationale for the staff recommendation is provided in Section 3.7.4 below.

Proposal 3: Staff recommend adopting Proposal 3. The rationale for the staff recommendation is provided in Section 3.7.4 below.

3.7.4 Rationale for Staff Recommendations

Staff recommend adoption of Proposal 1, Option 3 for the following reasons:

- **In addition to the settling parties, other parties have expressed support for establishing a process for the CPUC to accept applicant-prepared CEQA documents.**
  - The Sierra Club asserts, "In particular, Sierra Club supports the following proposed changes as reasonable: Section VIII(A)(7) and IX(C), allowing applicants to submit a draft California Environmental Quality Act ("CEQA") document with their applications". (*Sierra Club Comments on Joint Motion for Adoption of Settlement Agreement*, October 30, 2023, at 3)
  - RCRC asserts, "RCRC agrees with Southern California Edison (SCE) that Phase 2 should consider the Settlement Agreement's proposal to allow utilities to submit draft CEQA documents instead of a Proponent's Environmental Assessment. We believe this modest change could help avoid unnecessary duplication and project delays and agree with SCE that it "should be considered on an expedited basis during Phase 2 to enable utilities to quickly incorporate CEQA document rafting into any project application efforts that may be ongoing." (*Reply Comments of Rural County Representatives of California on Phase 2 Issues*, February 26, 2024, at 5)
- **Accepting applicant-prepared CEQA documents is consistent with the CEQA Guidelines and existing CEQA law.** As noted by the settling parties in the Joint Motion for Adoption of Phase 1 Settlement Agreement (page 27-28), CEQA Guidelines Section 15084(d) provides that a lead agency may "choose one of the following 28 arrangements or a combination of them for preparing a draft EIR … (3) Accepting a draft prepared by the applicant, a consultant retained by the applicant, or any other person." To ensure that the lead agency performs its own review of that draft, CEQA Guidelines Section 15084(e) further provides, "Before using a draft prepared by another person, the Lead Agency shall subject the draft to the agency's own review and analysis. The draft EIR which is sent out for public review must reflect the independent judgment of the Lead Agency." The settling parties assert that their proposal (Option 1) would be consistent with Section 15084(e) of the CEQA Guidelines, as it contemplates that although the applicant would prepare the CEQA document, CPUC staff would subject the draft to the agency's own review and analysis, issue

the document for public review as appropriate, respond to comments from responsible agencies and the public, and finalize the EIR or other CEQA document to reflect the Commission's independent judgment, all consistent with existing CEQA law. Options 2 and 3 contain these same attributes and would be similarly consistent with the CEQA Guidelines and existing CEQA law.

- **Requiring applicants to participate in pre-filing consultation during the development of a draft version of a CEQA document could accelerate the process for the CPUC to review and accept the applicant-submitted document.** Requiring applicants to initiate pre-filing consultation with the Energy Division not less than 12 months prior to submitting a draft version of a CEQA document would enable Energy Division staff and consultants to provide input on the format and content of the draft CEQA document (e.g., whether an EIR is required versus an MND) via meetings and preliminary review in the early stages of development rather than waiting to refine the approach in the application review process via deficiency letters. Proactive early pre-filing consultation with the Energy Division increases the likelihood that a draft document will be consistent with the needs of the Commission.
    - In its response to R.23-05-018 Data Request 01, SDG&E acknowledges that an earlier pre-filing review process could serve a useful purpose if it resulted in fewer deficiency notices: "As set forth in response to Question 1.e above, application filing could be accelerated if Energy Division were able and willing to determine that a Mitigated Negative Declaration is likely appropriate early in the IOU environmental review process, and thus negate the need to prepare a full PEA. If an earlier pre-filing review process resulted in fewer deficiency notices and an elimination of post-filing Energy Division data requests, it could serve a useful purpose." (*CPUC Data Request CPUC-SDGE-GO131-001 SDG&E Response*, March 8, 2024, at 16)
- **The settling parties' proposal (Option 1) does not specify the information required from applicants for development projects.** The PEA Checklist functions as a list "that [specifies] in detail the information that is required from any applicant for a development project", pursuant to Government Code Section 65940. In order to implement the in-lieu application process proposed by the settling parties, the Commission might need to establish one or more lists that specify in detail the information that is required from any applicant for a development project, pursuant to Government Code Section 65940. The PEA Checklist currently specifies the Commission's required application information. If the applicant-prepared draft CEQA document is not required to include the information in the PEA Checklist, then the Commission would need to establish a separate list (or lists) detailing the application requirements not already included in Section VIII and IX of GO 131-D. Proposal 1, Option 3 outlines a potential list of criteria that would apply to applicant-prepared CEQA documents. However, requiring applicant-submitted draft versions of initial studies or EIRs to include the contents of the Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments would allow applicants to choose to prepare a draft version of a CEQA document in lieu of a PEA while still providing

Energy Division staff and consultants the necessary information to process the application and prepare the draft CEQA document for public circulation.

- In its response to R.23-05-018 Data Request 01, Question 1e, SCE suggests that revising the PEA Checklist to request submission of more approximate (i.e., less specific) information could accelerate the application process: "Projects are often deemed incomplete if any component of the checklist is not fully addressed, therefore, preparing SCE's PEAs is a lengthy process given the need to include the required extensive and detailed information. Revising the PEA checklist to provide more approximations (e.g., range of pole heights and approximate structure locations) would enable utilities to file applications with the CPUC faster." (*Southern California Edison R.23-05-018 – Amend GO 131-D Data Request Set ED-SCE-001* [Question 1e]**,** March 8, 2024, at 1)
- PG&E similarly expresses support for streamlining the PEA Guidelines to require less detail, and offers an array of suggestions including the following: "Do not require more analysis on alternatives during CEQA review by the Commission than is required by CEQA. Do not require utilities to describe and evaluate all alternatives to the same level of detail as the proposed project. … Do not require utilities to submit detailed information, including Geographic information Systems (GIS) data, on the transmission and possibly distribution system to which the proposed project would interconnect or on the subject substation/transmission line beyond what is required for CEQA review. … Large, blanket buffers should be removed as they are often not appropriate for a specific project." (*Pacific Gas and Electric Company GO 131-D Update and Amend OIR Rulemaking 23-05-018 Data Response* [Question 1], March 8, 2024, at 8-9)

- **Limiting the types of applicant-prepared draft versions of CEQA documents to an initial study or EIR, as proposed in Options 2 and 3, would be consistent with CEQA Guidelines Section 15063.** Limiting the types of applicant-prepared draft CEQA document to an initial study or an EIR (rather than a draft EIR, MND, ND, addendum, or analysis of the applicability of an exemption from CEQA, as proposed by the settling parties) would be consistent with CEQA Guidelines Section 15063(c)—which states that the first purpose of an initial study is to "Provide the Lead Agency with information to use as the basis for deciding whether to prepare an EIR or a Negative Declaration"—and Section 15063(a), which states that "If the Lead Agency can determine that an EIR will clearly be required for the project, an Initial Study is not required but may still be desirable." The "initial study" is the technical term used for the draft initial study/mitigated negative declaration (IS/MND) or initial study/negative declaration (IS/ND) prior to the circulation of a draft to the public. Once the Energy Division has circulated the draft initial study to the public (with or without additional revisions to the applicant-submitted version), the document would be referred to as either an IS/MND or IS/ND. Adopting this technical change to the settling parties' proposal would better reflect the CEQA Guidelines and would make clear the nuance that Energy Division staff—not the applicant—would ultimately be responsible for circulating the draft document to the public.

Staff recommend Proposal 2 for the following reasons:

- **Section X is no longer substantive enough to remain a standalone section.** In the original version of GO 131-D, Section X was bifurcated into two subsections: Section X.A (now the remaining paragraph in Section X), and Section X.B, which referenced an Electric and Magnetic Fields (EMF) education program which ended on March 1, 1999. The Decision Addressing Phase 1 Issues (D.23-12-035) deleted Section X.B, leaving only a brief paragraph requiring that CPCN and PTC applications "shall describe the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields generated by the proposed facilities, in compliance with Commission order". This paragraph, while still providing useful information, is no longer substantively different enough from the primary lists of application requirements in Sections VIII and IX to justify remaining a standalone section.
- **Merging the required EMF information into the existing lists of application requirements in Sections VIII and IX would improve clarity for applicants.** Section X, in the version of GO 131-D effective December 14, 2023, essentially requires CPCN and PTC applications to include a discussion of measures taken or proposed by the applicant to reduce the potential exposure to EMFs generated by the proposed facilities. However, continuing to list this requirement separately from the primary lists of CPCN and PTC application requirements in Sections IX.A and IX.B could be confusing for applicants and could increase the likelihood that an applicant overlooks the EMF requirement. If an applicant accidentally omits the EMF information from an application, CPUC staff would need to send a deficiency letter to request correction of the omission, adding a delay to the application completeness review process that could have been avoided if the applicant had included the EMF information in the original application. Merging the EMF information from Section X to the relevant parts of Sections VIII and IX would simplify the organization of GO 131-D and improve the clarity of the application process.

Staff recommend Proposal 3 for the following reasons:

- **A range of parties expressed support for an earlier pre-filing review process.** In R.23-05-018 Data Request 01 (incorporated in Appendix C of this staff proposal), Energy Division staff asked utilities to respond to the following question: "Are there modifications to the pre-filing review process or application process that would incentivize applicants to initiate pre-filing consultation with the CPUC earlier in the project design process? Please explain."
  - In its response to R.23-05-018 Data Request 01, Question 2b, LS Power explained the value of early pre-filing and suggested additional incentives that could encourage utilities to engage in early pre-filing: "Since the bulk of the CEQA analysis typically precedes CPUC's consideration of a project proponent's application for a PTC or CPCN, the CPUC's CEQA guidance is relevant to discussions of pre-filing consultation. … As such, project proponents operating under the CEQA guidance already have reason to initiate early pre-filing consultation with CPUC. Additionally, project proponents are typically incentivized by internal schedules and required in-service dates to begin discussions with the CPUC shortly after CAISO selects a project. Such early consultation initiated by a project proponent allows

the CPUC sufficient time to identify appropriate project management teams, CEQA review consultants, and timelines to efficiently process an application. To further incentivize early pre-filing consultation for projects competitively awarded by CAISO, the CPUC could offer priority status with firm execution and completion schedules for both CEQA review and application processing after CEQA is complete for proponents that initiate pre-filing consultations within 60 days of award by CAISO. The CPUC would need to create a mechanism to incentivize the third-party CEQA consultants to meet the time schedule. Further, applicants should have the opportunity to file a draft CEQA document in lieu of a PEA, which would potentially save a year." (*LS Power Response Re: R.23-05-018 Data Request 01 – GO 131 Update Proceeding*, March 8, 2024, at 5)

- In its response to R.23-05-018 Data Request 01, Question 2b, SDG&E stated that an earlier pre-filing review process could serve a useful purpose if it resulted in fewer deficiency notices: "As set forth in response to Question 1.e above, application filing could be accelerated if Energy Division were able and willing to determine that a Mitigated Negative Declaration is likely appropriate early in the IOU environmental review process, and thus negate the need to prepare a full PEA. If an earlier pre-filing review process resulted in fewer deficiency notices and an elimination of post-filing Energy Division data requests, it could serve a useful purpose." (*CPUC Data Request CPUC-SDGE-GO131-001 SDG&E Response*, March 8, 2024, at 16)

- **Requiring earlier pre-filing consultation could facilitate greater coordination between utilities and the CPUC during the later stages of the project design process, which could even out the variation in design completeness levels at which different utilities report filing CPCN and PTC applications.** In R.23-05-018 Data Request 01, Question 1c, Energy Division staff asked utilities to respond to the following question: "At what percentage of design completeness (e.g., 30% design, 60% design) does your company typically aim to file an application with the CPUC?" The utility responses range from 30% (SCE, LS Power, and Horizon West Transmission, LLC) to 60% (PG&E), while SDG&E indicates that it files applications at 30% design completeness for underground projects and 60% for overhead projects.
    - SCE states, "SCE typically files applications with the CPUC when project design completeness is approximately 30%. This level of preliminary engineering and design typically provides sufficient detail to identify transmission facilities, structure types, structure locations, line routes, and pulling and stringing locations at a high level (desktop or field level). This level of design typically involves creating a Power Line Systems – Computer Aided Design and Drafting (PLS-CADD) model, initial AutoCAD drawings (plans and profiles), preliminary staking tables, initial access road and grading assessments, and preliminary geotechnical evaluations (typically desktop-level), among other activities. This level of detail provides adequate information for SCE to estimate anticipated environmental and ground disturbance impacts of the project." (*Southern California Edison R.23-05-018 – Amend GO 131-D Data Request Set ED-SCE-001* [Question 1c]**,** March 8, 2024, at 1)

- PG&E states, "PG&E aims to submit applications to the CPUC after internal approval of 60% design." (*Pacific Gas and Electric Company GO 131-D Update and Amend OIR Rulemaking 23-05-018 Data Response* [Question 2], March 8, 2024, at 7)
- SDG&E states, "After transmission and substation projects are approved internally and by the CAISO, SDG&E evaluates which projects would likely trigger an Advice Letter, PTC or CPCN, though the final conclusion isn't reached until SDG&E has a more complete design, typically between 30% and 60%. At 30% to 60% design, SDG&E typically already has a consultant on board to assist in preparing the PEA, which will also include the preparation of supporting technical studies such as biological technical reports, cultural and historic resources studies, etc. Our internal Key Performance Indicator to complete environmental analysis and assessment is 60% design, preferably after 30% design job walk. … In any case, for CPUC CPCN or PTC applications, SDG&E typically uses the 60% milestone for overhead facilities and 30% for underground facilities, which are largely located within franchise roadways or utility-owned properties and typically do not have the same level of impact as overhead facilities, particularly biological resources and aesthetics." (*CPUC Data Request CPUC-SDGE-GO131-001 SDG&E Response*, March 8, 2024, at 8-9)
- LS Power states, "LSPGC identifies routing and siting options during the initial proposal solicitation from CAISO. Upon selection by CAISO, LSPGC begins preliminary design and updated routing and siting to as described in response to data request 1 (b). LSPGC typically aims to submit a completed application and PEA with approximately 30% of the preliminary design completed." (*LS Power Response Re: R.23-05-018 Data Request 01 – GO 131 Update Proceeding*, March 8, 2024, at 3)
- Horizon West Transmission, LLC states, "Horizon West aims to file an application with the CPUC at approximately 30% design. … Not all details can be known at the time an application is submitted, but the better-defined and studied a project, the greater the probability that the CPUC deems the application complete and that delays can be avoided from significant changes occurring after the application is filed, or, having even greater an impact, after the CEQA review is complete. Horizon West's experience is that filing at approximately 30% design is the appropriate level of completeness to address these factors." (*Docket No. R.23-05-018, Horizon West Transmission, LLC (U222-E) Response to Data Request 01*, March 8, 2024, at 5)

- **Various parties expressed opposition to requiring utilities to file applications within a specified window after CAISO approval or prior to the CAISO-required in-service date; accordingly, instead of requiring additional filing deadlines relative to the CAISO process, the staff proposal focuses on requiring pre-filing consultation for all projects.** In R.23-05-018 Data Request 01 (incorporated in Appendix C), Question 2(a), Energy Division staff asked utilities to respond to the following questions: "Once a project is approved by CAISO, should the CPUC require the project proponent to file an application within a specified time window after CAISO approval (e.g., within one year) or within a specified time window prior to the required or forecasted in-service date (e.g., two years prior to the in-service date)? Alternatively, is it feasible to institute different filing deadlines based on project type and complexity? Please explain."

- In its response to R.23-05-018 Data Request 01, Question 2a, Horizon West Transmission, LLC states, "Horizon West does not believe that requiring proponents to file applications within a specified timeline after the project is approved via the CAISO's Transmission Plan and, for competitive projects, awarded through the CAISO competitive solicitation process, would be feasible or would meaningfully impact the total time from CAISO approval to project in-service date. In Horizon West's and consultants' experience, each transmission project is unique and involves unique requirements, e.g., the size and scope of the project, the number of environmental agencies and local governments that must be consulted, and the length of the resulting consultation processes that must be undertaken." (*Docket No. R.23-05-018, Horizon West Transmission, LLC (U222-E) Response to Data Request 01*, March 8, 2024, at 6)
- In its response to R.23-05-018 Data Request 01, Question 2a, LS Power explains, "Since achieving the in-service date (including all intermediate steps such as application preparation and permit issuance by CPUC) for a project is addressed contractually between the project proponent and CAISO, CPUC's imposition of an application submittal deadline would be unnecessary and would subvert CAISO's ability to manage its process for bringing grid assets online. As such, a CPUC-imposed application submittal deadline, whether implemented as a one-size-fits-all deadline or as a deadline customized by project type and complexity, would be inappropriate." (*LS Power Response Re: R.23-05-018 Data Request 01 – GO 131 Update Proceeding*, March 8, 2024, at 4)
- In its response to R.23-05-018 Data Request 01, Question 2a, PG&E states, "No. The CPUC should not require the project proponent to file an application within a specified time window after CAISO approval or relative to in-service dates. As explained in PG&E's November 21, 2023 response and in Response 1.b, there are dynamic factors that affect the timeline to filing. These dynamic factors include reprioritization of projects when there are competing priorities and limited funding, execution tasks and their time requirements, and project pausing projects if CAISO rescopes them in the TPP. Further, the timelines involved with these dynamic factors can vary depending on the unique circumstance of each project. Table 1.b provides specific examples of how these dynamic factors, as well as project-specific circumstances, can result in varying timelines between CAISO approval and General Order (GO) 131-D filings. Imposing unilateral timelines would fail to account for unique circumstances of each project." (*Pacific Gas and Electric Company GO 131-D Update and Amend OIR Rulemaking 23-05-018 Data Response* [Question 2], March 8, 2024, at 1)
- In its response to R.23-05-018 Data Request 01, Question 2a, SCE states, "SCE strongly recommends against establishment of a designated timeframe for filing an application following CAISO approval, as thoroughly discussed in SCE's Reply Comments on the Ruling Inviting Comment on Phase 2 Issues ("SCE's Reply Comments"). As discussed in SCE's Reply Comments, the rigorous project development process is not conducive to broad deadlines applied to all projects, irrespective of complexity, and especially with the substantial filing requirements for a Certificate of Public Convenience and Necessity or Permit to Construct. The Proponent's Environmental Assessment ("PEA") is a detailed

document that requires completion of preliminary engineering and extensive impact analysis. Unless the level of detail required in the PEA is reduced, a short window from CAISO approval to CPUC application filing is not likely to be feasible in most instances." (*Southern California Edison R.23-05-018 – Amend GO 131-D Data Request Set ED-SCE-001* [Question 2a]**,** March 8, 2024, at 1)

- In its response to R.23-05-018 Data Request 01, Question 2a, SDG&E states, "Each project that is approved by the CAISO is unique in its complexity, and a specified application timeline post approval would not be appropriate given the differences in desired in-service date, scope, habitat, communities, terrain, and the various other factors that need to be examined under CEQA for large transmission projects. For example, two projects may be very similar in scope, but one crosses previously disturbed terrain, reducing or eliminating the need for biological, cultural, and paleo surveys, where the other project may require all three. … Setting a deadline will not alter the tasks that must be completed or the time required to complete such tasks. Similarly, attempting to set a filing deadline a certain number of years before the desired in-service date presents its own set of issues. … Setting an application timeline based on the in-service date will likely lead to missed in-service dates for projects that don't fit neatly into a pre-defined box." (*CPUC Data Request CPUC-SDGE-GO131-001 SDG&E Response,* March 8, 2024, at 15-16)

3.8 Accelerate the CPUC CEQA Review Process

3.8.1 Problem Statement

On average, the CPCN process entails lengthier timelines than the PTC process. A June 2023 memo published by Cal Advocates analyzed 14 projects (including seven CPCN projects and seven PTC projects) and found that the average duration of the development process for CPCN projects (i.e., 200 kV or greater) was 11 years and nine months, while the average duration for PTC projects (i.e., 50-200 kV) was 10 years and three months.[14] Pursuant to Public Utilities Code Section 1002.3, the CPCN process requires the CPUC to prepare a detailed assessment of the need for and the estimated cost of a proposed project, while the PTC process does not require a detailed review of project cost and need. Additionally, some statutory requirements exist for the CPCN process that do not apply to the PTC process (see Public Utilities Code Section 1001 et seq.).

However, the CPCN versus PTC distinction is not the only factor that contributes to the permitting timeframe for a project, and some CPCNs are issued within less time than PTCs. Among other factors, the

[14] Transmission Project Development Timelines in California, Cal Advocates, June 12, 2023; available at https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/transmission-project-development-timelines-in-california

level of environmental review that is required for a particular project—e.g., whether the CPUC must prepare an EIR or an MND—can also affect the duration of permitting. Section 15107 of the CEQA Guidelines states that MNDs and NDs must be completed within 180 days of deeming an application complete with the option of an extension for an additional 90 days (resulting in a total of 270 days), while Section 15108 of the CEQA Guidelines states that EIRs must be completed within one year of deeming an application complete, with the option to extend this timeline by an additional 90 days (resulting in a total of 455 days). The foreword to the CPUC's PEA Guidelines includes an analysis of the CEQA review and permit issuance timeframes for 108 applications filed with the CPUC between 1996 and 2019, including 49 that required an EIR and 56 that required an IS/MND. In this analysis, CPUC staff found that on average, the Commission issued decisions for EIR projects within 29 months of application filing (25 months from application deemed complete) and issued decisions for MND projects within 19 months of application filing (15 months from application deemed complete) (*Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments*, Version 1.0, November 2019, Table 1).

Even in a scenario where the CPUC CEQA review process is completed quickly, permitting timelines can be extended by factors beyond the control of CPUC Energy Division staff, such as refinement of the project planning and design process, the quality of the information provided by the applicant, the emergence of any local opposition to a project, and the permitting processes of other State or federal agencies. When these factors compound, they can substantially increase the complexity of the permitting process and can contribute to commensurate delays in the completion of CEQA review. Section 15110 of the CEQA Guidelines acknowledges that projects that also involve approvals by federal agencies (e.g., projects subject to the National Environmental Policy Act [NEPA]) may take longer than the timeframes outlined in Sections 15107 and 15108.

In the aforementioned Transmission Project Development Timelines in California study, Cal Advocates found that utilities file CPCN applications an average of four years after the corresponding project is approved in a CAISO Transmission Plan, a delay which can place additional pressure on the CPUC CEQA review process as a critical-path requirement that must be met if the applicant is to construct the project prior to the CAISO-required in-service date. An incomplete or otherwise insufficient application may require extensive corrections, multiple deficiency letters, and ongoing negotiation between CPUC staff and the applicant during the application completeness review, contributing to delays before the CPUC CEQA review has officially begun. Local opposition to a project can lead to delays such as litigation, court-mandated construction stays, late-stage project design changes, and protracted CEQA review associated with the processing of extensive public comments and/or the recirculation of the draft CEQA document.

Even when the CPUC is the lead agency for CEQA review, the existence of other State and federal permitting requirements—e.g., projects that cross federally managed lands and therefore require NEPA review, or projects that require special permits for potential impacts to sensitive resources such as waterways, coastal resources, or special-status species—can introduce additional complexity and unpredictability into the permitting process due to CEQA's requirement to coordinate with such agencies.

Project delays are often caused by factors outside of the CPUC's control. Public opposition to projects under CEQA review by the CPUC can contribute to delays due to expanded public outreach and consultation efforts, the need to address a greater volume of comments in the CEQA document and application proceeding, and in some cases the need to respond to legal challenges. Other causes of delay include changes in demand forecast and the need for additional alternatives analysis. SCE's Presidential 66 kV Substation Project (Application A.08-12-023, filed December 22, 2008) is an example of a project encountering public controversy and changes to demand. In this case, there were local community objections relating to the project's proximity to the Reagan Presidential Library. Tribal concerns with the project required extended consultation. Additionally, the demand forecast for the project had changed due to the 2008 recession. While this project was subject to a PTC application and therefore did not require an extensive evaluation of project need, the change in load forecast still contributed to delays in the CEQA review timeline. Finally, a new alternative was introduced after completion of the Final EIR, requiring an amendment prior to certification.

The PG&E Vierra Reinforcement Project in San Joaquin County (Application No. A.18-06-004, filed June 6, 2018) was delayed in connection with the development of a pilot program wherein the CPUC contracted the services of CEC staff to prepare a draft CEQA document (IS/MND) under the direction of a CPUC Energy Division project manager. The intent of the pilot program was to explore options to use available state resources beyond the CPUC to perform tasks, such as technical CEQA analyses, that are typically contracted to private sector consultants. However, in the case of the Vierra Reinforcement Project, the draft CEQA document still required quality control and revisions, and the CPUC Energy Division ultimately contracted with a consulting firm to make the necessary revisions to the document and finalize the Draft IS/MND for public review. The Energy Division also hired a separate consulting firm to implement the mitigation monitoring program. Furthermore, the CPUC and CEC were still obligated to follow their own internal approval processes, which compounded to lengthen the overall process. The CPUC also contracted with the CEC for the Ravenswood-Cooley Landing 115 kV Reconductoring Project (Application No. A. 17-12-010) as part of the same pilot program. The pilot program was subsequently discontinued.

One proposal that has been raised in the R.23-05-018 proceeding record and beyond is the imposition of additional deadlines on the CPUC CEQA review process. In the Joint Motion for Adoption of Phase 1 Settlement Agreement submitted by PG&E, SCE, and SDG&E on September 29, 2023, settling parties proposed requiring the CPUC to determine whether to adopt or certify the appropriate CEQA document and issue the requested CPCN or PTC no later than 270 days after an application is deemed complete (see Proposal 3). Another party-submitted proposal considered herein is the Cal Advocates proposal to establish a new process for prioritizing CAISO-approved policy-driven transmission projects (see Proposal 4), as outlined in Cal Advocates' opening comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues. Finally, in this section, staff present alternative proposals (see Proposals 1 and 2) that would clarify the existing timeframes in the CEQA Guidelines and would establish a pilot program to evaluate criteria that could enable projects to meet a 270-day or 455-day deadline. Staff recommend Proposals 1 and 2, rather than Proposal 3 or Proposal 4, to ensure that any changes to accelerate the CPUC CEQA review process are carefully considered, feasible to implement, and compliant with CEQA and other legal obligations.

3.8.2 Proposals

Proposal 1: Clarify Applicability of Existing CEQA Review Time Limits

This proposal would modify Sections IX.B and XVI of GO 131-D to reference the existing CEQA review time limits outlined in the CEQA Guidelines and to include guidance regarding which types of projects may be eligible for a 455-day or 270-day CEQA review timeframe, as detailed below.

Section IX.B.5 would be modified as follows:

> 5. If the initial study identifies potentially significant environmental effects, the Energy Division will prepare an EIR. The severity and nature of the effects, the feasibility of mitigation, the existence and feasibility of alternatives to the project, and the benefits of the project would all be considered by the Commission in deciding to construct. ~~The Commission intends to issue a permit to construct or disapprove the project within eight months of accepting the application as complete. This time limit may be extended if necessary to comply with the requirements of CEQA, but may not exceed the time limits specified in CEQA (for the preparation of an EIR).~~

Section XVI, CEQA Compliance, would be modified as follows:

> Pursuant to Sections 15107 and 15110 of the CEQA Guidelines, the Commission strives to complete Proposed Final MNDs or NDs for projects without federal agency involvement within 270 days or sooner from the date the PTC or CPCN application is deemed complete. Pursuant to Sections 15108 and 15110 of the CEQA Guidelines, the CPUC would strive to complete Proposed EIRs for projects without federal agency involvement within 455 days or sooner from the date that the application is deemed complete. Sections 15109 and 15110 of the CEQA Guidelines shall apply regarding the suspension of time periods and projects with federal involvement.
>
> Projects requiring CPUC approval of a PTC that qualify for an MND or ND and have no federal agency involvement could involve completion of CEQA review within 270 days. In accordance with Section 15070 of the CEQA Guidelines, CPUC shall prepare or have prepared a proposed ND or MND for a project when:
>
> A. The initial study shows that there is no substantial evidence (as defined in Section 15384 of the CEQA Guidelines), in light of the whole record before the agency, that the project may have a significant effect on the environment, or
> B. The initial study identifies potentially significant effects, but:
>
>   1. Revisions in the project plans or proposals made by, or agreed to by the applicant before a proposed mitigated negative declaration and initial study are released for public review would avoid the effects or mitigate the effects to a point where clearly no significant effects would occur, and
>   2. There is no substantial evidence, in light of the whole record before the agency, that the project as revised may have a significant effect on the environment.

Staff recommend adoption of Proposal 1. The rationale for the staff recommendation is provided in Section 3.8.4 below.

Proposal 2: Establish a Pilot Program for Accelerated CEQA Review

This proposal would use the R.23-05-018 Phase 2 decision to order staff to develop a pilot program to evaluate which criteria and/or process changes could lead to successful completion of CEQA documents within the timeframes identified in the CEQA Guidelines (i.e., 270 days for an MND or ND, or 455 days for an EIR). In contrast to the settling parties' proposal outlined in Proposal 3, this proposal would not involve modifications to GO 131-D.

In the pilot program, Energy Division staff would identify at least two projects where an MND could potentially be completed on a 270-day schedule (or faster) and at least two projects where an EIR could potentially be completed on a 455-day schedule (or faster), including, if possible, at least one project from each of the major IOUs (i.e., PG&E, SCE, and SDG&E) and a mixture of competitively bid and non-competitively bid projects. The Energy Division would then strive to complete the selected projects within the target timeframe while using metrics to evaluate the success of the pilot program.

Potential selection criteria for a project to be eligible for the pilot program could include, but would not be limited to:

- Projects qualifying for a PTC application (rather than a CPCN);
- Projects that do not require approvals from a federal agency;[15]
- Projects where the applicant prepares a draft CEQA document rather than a PEA (if Section 3.7, Proposal 1 is adopted);
- A commitment by the applicant to initiate pre-filing consultation at least six (6) months prior to application submittal and provide at least 12 months' notice to the CPUC prior to application;
- Completion and delivery of all technical studies before or during pre-filing consultation with the CPUC; and
- Projects that are expected to be smaller, less complex, and/or located within disturbed areas, including but not limited to:
  - Extensions, expansions, upgrades, or other modifications to existing electrical transmission facilities;
  - Generator tie-ins near or adjacent to existing transmission lines or substations; or
  - Substation expansions.

In addition to the above criteria, the Commission could strive to select projects for the pilot program that are expected to facilitate the delivery of clean energy resources to the power grid (e.g., projects that connect

[15] Although staff do not recommend including projects with federal involvement in the first iteration of the pilot program, the Commission could consider a similar pilot for projects with federal involvement following the successful completion of the pilot program for MNDs and EIRs without federal involvement.

renewable generation facilities to the grid or expand grid capacity), in acknowledgement of the intent of SB 529 to accelerate the review and approval of such projects.

The Energy Division could track and report the following metrics to measure the success of the effort to complete the CEQA document within the target timeframe:

- Time from application deemed complete to Proposed Final CEQA document;
- Time from application deemed complete to draft CEQA document;
- Number of data requests;
- Project chronology;
- Days with public for review; and
- Number of public comment letters.

Staff recommend adoption of Proposal 2. The rationale for the staff recommendation is provided in Section 3.8.4 below.

Proposal 3: Establish 270-Day Deadline for CPUC CEQA Review

This proposal would amend Sections IX.A and IX.B to require that the CPUC determine whether to adopt or certify the appropriate CEQA document and issue the requested CPCN or PTC no later than 270 days after a CPCN or PTC application is deemed complete, as proposed by settling parties in the Joint Motion for Adoption of Phase 1 Settlement Agreement submitted on September 29, 2023.

Section IX.A.2 would be modified and bifurcated between the existing Section IX.A.2 and a new Section IX.A.3 as follows, with new text underlined in red and deleted text in red strikethrough:

2. No later than 30 days after the filing of the application the Commission staff shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application. The utility shall correct any deficiencies within 60 days thereafter, or explain in writing to the Commission staff why it is unable to do so. It shall include in any such letter an estimate of when it will be able to correct the deficiencies. ~~Upon correction~~ The application shall be deemed complete (i) 30 days after submission of ~~any deficiencies in~~ the application~~,~~ unless the utility is notified of deficiencies as set forth above; (ii) if the utility is notified of deficiencies as set forth above, then 30 days after the utility submits information in response to such notice unless the utility is notified within that 30 days that previously-identified deficiencies remain; or (iii) immediately upon the Commission's determination that any additional information requested by Commission staff has been provided, whichever comes first.

3. Once the application is deemed complete, the Commission staff shall determine whether CEQA applies, and if so, whether a Negative Declaration, Mitigated Negative Declaration or an EIR has been or will be prepared, and the process required by CEQA and Commission Rules of Practice and Procedure 2.4 and 2.5 will be followed in addition to the Commission's standard decision-making process for applications. ~~The~~ Unless required sooner by Paragraph 5 below, the

Commission shall issue a decision within the time limits prescribed by Government Code Sections 65920 et seq. (the Permit Streamlining Act).

This proposal would create a new Section IX.A.4 and IX.A.5, which would read as follows:

4. The Commission may request additional information from the utility to address comments by public agencies on the scope and content of the information that is required to be included in a CEQA Document. The utility shall provide to the Commission the requested information within 30 days of receiving the request.

5. Unless a shorter time period is required by state law, no later than 270 days after the application is deemed complete, or as soon as practicable thereafter, the Commission shall determine whether to adopt or certify the appropriate CEQA Document and to issue the requested CPCN; provided, however, the time to determine whether to adopt or certify the appropriate CEQA Document and issue the requested CPCN may be extended if one or more of the following occurs: (a) the Commission is required to recirculate an environmental impact report pursuant to Section 15088.5 of Title 14 of the California Code of Regulations; (b) substantial changes are proposed in the project that may involve new significant environmental effects or a substantial increase in the severity of previously identified significant effects; (c) substantial changes occur with respect to the circumstances under which the project is undertaken that may involve new significant environmental effects or a substantial increase in the severity of previously identified significant effects; (d) new information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence before the Commission publishes the notice of availability of the relevant CEQA document for public review, is submitted that may require additional analysis and consideration; or (e) the Commission, in consultation with the Department of Fish and Wildlife or the State Water Resources Control Board, if applicable, determines that additional time is necessary to obtain information and conduct surveys, including due to seasonal constraints

Section IX.B.2 would be modified and bifurcated between the existing Section IX.B.2 and a new Section IX.B.3 as follows, with new text underlined in red and deleted text in red strikethrough:

2. No later than 30 days after the filing of the application for a permit to construct, the Energy Division shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application. Thereafter, within 30 days, the utility shall correct any deficiencies or explain in writing to the Energy Division when it will be able to correct the deficiencies or why it is unable to do so. ~~Upon correction~~ The application shall be deemed complete (i) 30 days after submission of ~~any deficiencies in~~ the application~~,~~ unless the utility is notified of deficiencies as set forth above; (ii) if the utility is notified of deficiencies as set forth above, then 30 days after the utility submits information in response to such notice unless the utility is notified within that 30 days that previously-identified deficiencies remain; or (iii) immediately upon the Commission's determination that any additional information requested by Commission staff has been provided, whichever comes first.

3. Once the application is deemed complete, the Energy Division shall determine whether CEQA applies, and if so, whether a Negative Declaration, Mitigated Negative Declaration or an EIR must be prepared, and the process required by CEQA and the Commission's Rules of Practice and Procedure 2.4 and 2.5 will be followed.

Section IX.B.3 and IX.B.4 would be changed to IX.B.4 and IX.B.5, respectively, and would be modified as follows, with new text underlined in red and deleted text in red strikethrough.

4. If the Commission finds that a project properly qualifies for an exemption from CEQA, the Commission will promptly grant the permit to construct.

5. If the Energy Division determines~~, after completing its initial study,~~ that the project would not have a significant adverse impact on the environment, the Energy Division will ~~prepare~~ adopt a Negative Declaration. If the ~~initial study~~ Energy Division identifies potential significant effects, but the utility revises its proposal to avoid those effects, then the Commission ~~could~~ will adopt a Mitigated Negative Declaration. In either case, the Commission will promptly grant the permit to construct.

Section IX.B.5 would be changed to IX.B.6 and would be modified as follows, with new text underlined in red and deleted text in red strikethrough.

6. If the ~~initial study~~ Energy Division identifies potentially significant environmental effects~~,~~ that the utility does not revise its proposal to avoid, and the project is not exempt under CEQA, the Energy Division will prepare an EIR unless the applicant has elected or elects to prepare a draft EIR pursuant to Section IX.C.1 below. The severity and nature of the effects, the feasibility of mitigation, the existence and feasibility of alternatives to the project, and the benefits of the project would all be considered by the Commission in deciding whether to grant or deny the permit to construct. ~~The Commission intends to issue a permit to construct or disapprove the project within eight months of accepting the application as complete. This time limit may be extended if necessary to comply with the requirements of CEQA, but may not exceed the time limits specified in CEQA (for the preparation of an EIR).~~

This proposal would add a new Section IX.B.7 and IX.B.8, which would read as follows:

7. The Commission may request additional information from the utility to address comments by public agencies on the scope and content of the information that is required to be included in a CEQA Document. The utility shall provide to the Commission the requested information within 30 days of receiving the request.

8. Unless a shorter time period is required by state law, no later than 270 days after the application is deemed complete, or as soon as practicable thereafter, the Commission shall determine whether to adopt or certify the appropriate CEQA Document and to issue the requested PTC; provided, however, the time to determine whether to adopt or certify appropriate CEQA Document and issue the requested PTC may be extended if one or more of the following occurs: (a) the Commission is

> required to recirculate an environmental impact report pursuant to Section 15088.5 of Title 14 of the California Code of Regulations; (b) substantial changes are proposed in the project that may involve new significant environmental effects or a substantial increase in the severity of previously identified significant effects; (c) substantial changes occur with respect to the circumstances under which the project is undertaken that may involve new significant environmental effects or a substantial increase in the severity of previously identified significant effects; (d) new information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence before the Commission publishes the notice of availability of the relevant CEQA document for public review, is submitted that may require additional analysis and consideration; or (e) the Commission, in consultation with the Department of Fish and Wildlife or the State Water Resources Control Board, if applicable, determines that additional time is necessary to obtain information and conduct surveys, including due to seasonal constraints

Finally, existing Section IX.B.6 would be changed to IX.B.9, but would not be otherwise modified by this proposal.

Staff do not recommend adoption of Proposal 3. The rationale for the staff recommendation is provided in Section 3.8.4 below.

Proposal 4: Prioritize Policy-Driven CAISO TPP Projects

This proposal would modify Section IX.B to establish an expedited permitting process for policy-driven CAISO-approved electrical transmission projects, as proposed by the California Public Advocates Office (Cal Advocates) in its opening comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues (*Public Advocates Office Opening Comments on the Administrative Law Judges' Ruing Inviting Comment on Phase 2 Issues*, February 5, 2024, at 13-15) and in a memo published April 29, 2024.[16]

Staff do not recommend adoption of this proposal at this time, but do recommend further consideration of the Cal Advocates proposal beyond Phase 2 of the R.23-05-018 proceeding. The rationale for the staff recommendation is provided in Section 3.8.4 below.

3.8.3 Staff Recommendations

Summary of staff recommendations:

Proposal 1: Staff recommend the adoption of Proposal 1. The rationale for staff's recommendation is provided in Section 3.8.4 below.

[16] Prioritization of Policy-Driven Transmission Projects Proposal, https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/prioritization-of-policy-driven-transmission-projects

Proposal 2: Staff recommend implementation of Proposal 2 in addition to Proposal 1. The rationale for staff's recommendation is provided in Section 3.8.4 below.

Proposal 3: Staff do not recommend the adoption of Proposal 3 at this time. The rationale for staff's recommendation is provided in Section 3.8.4 below.

Proposal 4: Staff do not recommend adoption of Proposal 4 at this time, but do recommend further consideration of the Cal Advocates proposal beyond Phase 2 of the R.23-05-018 proceeding. The rationale for the staff recommendation is provided in Section 3.8.4 below.

3.8.4 Rationale for Staff Recommendations

Staff recommend adoption of Proposal 1 for the following reasons:

- **Proposal 1 is consistent with the time limits for EIR preparation listed in the CEQA Guidelines**. Unlike Proposal 3, which would establish a 270-day time limit for all projects irrespective of the CEQA document type, Proposal 1 would instead provide applicants with realistic and reasonable expectations for CEQA document preparation timeframes, citing the relevant sections of the CEQA Guidelines.

Staff recommend the adoption of Proposal 2 for the following reasons:

- **The pilot program would help evaluate reasonable criteria whereby qualifying projects could potentially be completed within 270 or 455 days.** The pilot program would acknowledge that every CEQA project is different, and that preparing a CEQA document within the 270-day or 455-day time limit will be more feasible to achieve for some projects than others. In implementing the pilot program, staff would strive to select such projects according to a range of realistic criteria—e.g., projects that qualify for the PTC process and do not require involvement from federal agencies. Additionally, the pilot program would acknowledge that early, proactive consultation on the part of the applicant (e.g., initiating pre-filing consultation at least six months prior to the application submittal and providing early notice to Commission staff) and submittal of complete, thorough application materials (e.g., completing all technical studies prior to the application submittal) can increase the likelihood that a project will meet the 270-day or 455-day deadline.
- **The results of the pilot program could be used to enable continued process development.** Staff propose to track a list of metrics during completion of pilot projects in order to determine which steps in the process are taking the longest to complete. Where staff and applicants have control over milestone timelines, staff and applicants can focus on improvements in these areas, potentially resulting in the delivery of a report or report(s) recommending staff-level process improvements and other actions. In responses to R.23-05-018 Data Request 01, parties suggest various process improvements that could accelerate the application processing and CEQA review process without requiring imposition of a 270-day deadline for all projects.
  - In its response to R.23-05-018 Data Request 01, Question 6c, LS Power suggests, "LSPGC recommends conducting processes in parallel rather than in series. On previous LSPGC

projects (Gates and Round Mountain) significant time was taken between the CEQA process and PTC briefing and drafting the proposed decision. These actions were taken in series, with the CEQA process being completed prior to the PTC briefing and drafting the proposed decision. LSPGC recommends that the CPUC allow for these processes to take place in parallel (i.e., when the draft CEQA document is available for public comment) rather than in series, which may allow for efficiencies in full project approval." (*LS Power Response Re: R.23-05-018 Data Request 01 – GO 131 Update Proceeding*, March 8, 2024, at 10)

  - In its response to R.23-05-018 Data Request 01, Question 1e, PG&E suggests: "The utilities as well as Energy Division staff are often frustrated by the slow process required for State hiring. PG&E suggests exploring ways to expedite hiring CPUC consultants. Without CPUC consultants, the prefiling process is not effective." (*Pacific Gas and Electric Company GO 131-D Update and Amend OIR Rulemaking 23-05-018 Data Response* [Question 1], March 8, 2024, at 8) PG&E further suggests streamlining the PEA Guidelines and working with CAISO to develop criteria when siting third-party generation facilities.

- **Selecting policy-driven projects for the pilot program that are expected to facilitate the delivery of clean energy resources would be consistent with the intent of SB 529.** A primary goal of SB 529 was to facilitate the delivery of clean energy resources to the power grid by enabling a more expedited review and approval process for upgrades to existing transmission system facilities in existing corridors. If Proposal 2 is adopted, the Commission could strive to select projects for the pilot program that are expected to facilitate the delivery of clean energy, e.g., projects that interconnect renewable generation facilities to the grid. Although the selection of appropriate projects for a pilot program would be dependent on a variety of factors, including project timing and availability, using one or more policy-driven projects that support clean energy delivery, if feasible, would be consistent with the intent of SB 529.
  - The Assembly Committee on Utilities and Energy provided the following author statement from Senator Hertzberg, the author of SB 529, in the summary for its June 29, 2022 hearing: "California is facing an unprecedented need for renewable energy resources to power the state's electric grid over the next 10 to 20 years. This heightened need is driven by increased customer demand for clean energy, the continued electrification of transportation and other industries, and state greenhouse gas reduction and renewable energy objectives. If California is going to meet increased capacity needs and achieve clean energy goals, the state must support the development of cost-effective, environmentally responsible transmission projects that can reliably deliver renewable resources throughout the state. With this principle in mind, SB 529 enables a more expedited review and approval process for upgrades to existing transmission system facilities in existing corridors, or "rights of way." By removing barriers to these critical improvements, SB 529 facilitates the delivery of clean energy resources to the power grid and helps lower the costs of achieving state clean energy goals. Importantly, SB 529 expedites approvals least likely to pose rate concerns, still ensures CEQA is complied with through the PTC process, and minimizes development costs for ratepayers." (*Author Statement of Senator Hertzberg for SB 529, Assembly Committee on Utilities and Energy Hearing Summary*, June 29, 2022)

- **Establishing a pilot program would acknowledge that a number of parties, including but not limited to the settling parties, have expressed support for accelerating the CPUC CEQA review process.**
    - The Sierra Club states, "In particular, Sierra Club supports the following proposed changes as reasonable: … Section IX(A)(2), (4), (5), establishing additional deadlines for the Commission's evaluation of transmission line facilities over 200 kV; Section IX(B)(2), (7), (8), establishing additional deadlines for the Commission's evaluation of transmission line facilities between 50 kV and 200 kV and substations larger than 50 kV". (*Sierra Club Comments on Joint Motion for Adoption of Settlement Agreement*, October 30, 2023, at 3)

Staff recommend against the adoption of Proposal 3 for the following reasons:

- **Setting a deadline does not change the time required to complete key steps in the CEQA process. Furthermore, requiring a 270-day time limit for EIRs would be inconsistent with the time limits in the CEQA Guidelines.** The settlement agreement proposes that a 270-day time limit be required both for EIRs and for MNDs or NDs once an application is deemed complete, regardless of whether there is federal involvement in the project. However, Section 15108 of the CEQA Guidelines calls for the preparation of EIRs within one year of deeming an application complete, with the option for an extension of this timeline by an additional 90 days (resulting in a total of 455 days). Section 15107 of the CEQA Guidelines calls for completion of MNDs or NDs within 180 days of deeming an application complete with the option of an extension for an additional 90 days (resulting in a total of 270 days). Section 15110 of the CEQA Guidelines further acknowledges that projects that also involve approvals by federal agencies could take longer than the timelines outlined in Sections 15107 and 15108 of the CEQA Guidelines.
    - These overall timeframes in turn contain additional required timeframes for certain steps in the CEQA process, e.g., public review of a draft CEQA document. Statutory time periods for public and agency comments and responses to public agency comments comprise 100 days of an EIR process (CEQA Guidelines Sections 15103 and 15105, and Section 21092.5 of CEQA), leaving only 170 days, or approximately four months, to complete the evaluation, analysis, and consultations required by CEQA within a 270-day time limit.
    - In its response to R.23-05-018 Data Request 01, Question 2a, SDG&E points out that setting a deadline does not inherently alter the tasks that must be completed or the time required to complete such tasks: "Each project that is approved by the CAISO is unique in its complexity, and a specified application timeline post approval would not be appropriate given the differences in desired in-service date, scope, habitat, communities, terrain, and the various other factors that need to be examined under CEQA for large transmission projects. … Setting a deadline will not alter the tasks that must be completed or the time required to complete such tasks." *(CPUC Data Request CPUC-SDGE-GO131-001 SDG&E Response,* March 8, 2024, at 15-16*)* SDG&E submitted this response to a question about the appropriateness of application filing deadlines, but SDG&E's arguments are relevant to the question of imposing additional deadlines on CPUC CEQA review.

- **Meeting a 270-day time limit can be challenging even for MNDs and NDs due to circumstances beyond the control of the CPUC.** The CPUC strives to complete a Proposed Final MND or ND within 270 days once an application is deemed complete. However, timelines for completion of MNDs or NDs can extend beyond 270 days depending upon factors such as the complexity of the project issues and the level of controversy (e.g., many public comments). The full complexity of a given project may not be visible until the CEQA process is well underway, and issues can arise later in the process that were not known or foreseeable at the outset.
  - In its response to R.23-05-018 Data Request 01, Question 2a, SCE acknowledges that "the rigorous project development process is not conductive to broad deadlines applied to all projects" and that project complexity is often not known until more detailed design and environmental analysis activities are completed, stating, "As discussed in SCE's Reply Comments, the rigorous project development process is not conducive to broad deadlines applied to all projects, irrespective of complexity, and especially with the substantial filing requirements for a Certificate of Public Convenience and Necessity or Permit to Construct. … Requiring utilities to file within a specified timeframe does not account for factors outside the utilities' control, such as seasonal limitations on environmental surveys. It is not clear whether it would be feasible to institute different filing deadlines based upon project type and complexity, as oftentimes complexity is not known until more detailed design and environmental analysis activities are completed." (*Southern California Edison R.23-05-018 – Amend GO 131-D Data Request Set ED-SCE-001* [Question 2a]**,** March 8, 2024, at 1) SCE submitted this response to a question about the appropriateness of application filing deadlines, but SCE's arguments are similarly relevant to consideration of the settling parties' proposal to impose "broad deadlines applied to all projects, irrespective of complexity" for CPUC CEQA review.
- **Requiring a 270-day time limit for EIR preparation would risk rushing the CEQA process and completing critical steps without sufficient substantial evidence, potentially degrading the quality of CPUC CEQA documents.** The CPUC has emphasized that CEQA documents be both high-quality and legally defensible. The purpose for this high standard of CEQA review is manifold: to honor the intention of CEQA to both disclose and mitigate potential environmental impacts, to maintain the public's trust in the agency's CEQA processes, and to discourage post-certification legal challenges. To require that the process must be completed within a specified timeframe risks degrading the quality of the environmental review process and of the resulting environmental document that is ultimately presented to CPUC Commissioners for certification. Requiring a 270-day time limit for preparation of EIRs would risk rushing the EIR process by completing the following steps without sufficient substantial evidence: consideration of general public and agency comments received during the 30-day scoping period for an EIR; adequate and complete identification and evaluation of a reasonable range of alternatives; meaningful Tribal consultation; consideration of general public and agency comments during the 45 to 60-day comment period for a Draft EIR; and adequate response to public comments and incorporation of revisions into the Proposed Final EIR. Condensing these analyses, required public noticing and comment periods, and meaningful response to public and agency comment into 270 days would

rush the process, would not be consistent with existing timelines in CEQA for EIRs, could present significant risk of challenge, and therefore, would not be appropriate.

- In preparing CEQA documents, the CPUC is responsible for the adequacy and objectivity of the document (Section 15084[e], CEQA Guidelines). A CEQA document is an informational document which will inform public agency decision makers and the public generally of the significant environmental effect of a project, identify possible ways to minimize the significant effects, and for EIRs, to describe reasonable alternatives to the project. The public agency shall consider the information in the CEQA document along with other information which may be presented to the agency and the information in a CEQA document may constitute substantial evidence in the record to support the agency's action on the project if its decision is later challenged in court (CEQA Guidelines Sections 15121[a] and [c]).
- A CEQA document must identify and focus on the significant effects of the proposed project on the environment, including impacts associated with up to 20 issue areas (e.g., air quality, biological resources, noise etc.). Direct and indirect significant effects of the project on the environment shall be clearly identified and described, giving due consideration to both the short-term and long-term effects. The discussion must include relevant specifics of the area, the resources involved, physical changes, alterations to ecological systems, and changes induced in population distribution, population concentration, the human use of the land (including commercial and residential development), health and safety problems caused by the physical changes, and other aspects of the resource base such as water, historical resources, scenic quality, and public services. The EIR shall also analyze any significant environmental effects the project might cause or risk exacerbating by bringing development and people into the area affected. For example, a CEQA document should evaluate any potentially significant direct, indirect, or cumulative environmental impacts of locating development in areas susceptible to hazardous conditions (e.g., floodplains, coastlines, wildfire risk areas), including both short-term and long-term conditions, as identified in authoritative hazard maps, risk assessments or in land use plans addressing such hazards areas. These analyses must be supported by substantial evidence, and the CEQA document must reflect the CPUC's independent judgment.
- CEQA requires more than merely preparing environmental documents. The CEQA document by itself does not control the way in which a project can be built or carried out. Rather, when CEQA document shows that a project would cause substantial adverse changes in the environment, the governmental agency must respond to the information by one or more of the following methods (Section 15002[h], CEQA Guidelines):
  - Changing a proposed project;
  - Imposing conditions on the approval of the project;
  - Adopting plans or ordinances to control a broader class of projects to avoid the adverse changes;
  - Choosing an alternative way of meeting the same need;
  - Disapproving the project;

    - Finding that changing or altering the project is not feasible;
    - Finding that the unavoidable significant environmental damage is acceptable as provided in Section 15093.

- **Requiring a 270-day time limit for EIR preparation would risk constraining scoping, interagency and Tribal consultation, and public participation.** Scoping is required to identify the range of actions, alternatives, mitigation measures, and significant effects to be analyzed in depth in an EIR and in eliminating from detailed study issues found not to be important (CEQA Guidelines Section 15083[a]). Scoping is also an effective way to bring together and resolve the concerns of affected federal, state, and local agencies, the proponent of the action, and other interested persons including those who might not be in accord with the action on environmental grounds (CEQA Guidelines Section 15083[b]). Public participation is an essential part of the CEQA process. The CEQA Guidelines direct each public agency to include provisions in its CEQA procedures for wide public involvement, formal and informal, consistent with its existing activities and procedures, in order to receive and evaluate public reactions to environmental issues related to the agency's activities (CEQA Guidelines Section 15201). Additionally, the CEQA Guidelines direct that the Lead Agency shall provide adequate time for other public agencies and members of the public to review and comment on a draft EIR or Negative Declaration that it has prepared (CEQA Guidelines Section 15203).
    - Projects subject to CPCNs or PTCs often involve long, linear projects that span multiple jurisdictions and that meet the definition of Projects of Statewide, Regional, or Areawide Significance under CEQA (Section 15206, CEQA Guidelines), including projects that have the potential for causing significant effects on the environment extending beyond one city or county; projects that would substantially affect sensitive wildlife habitats including but not limited to riparian lands, wetlands, bays, estuaries, marshes, and habitats for rare and threatened species; and projects that would be located in, and substantially impact, areas of critical environmental sensitivity (e.g., the Lake Tahoe Basin, Sacramento-San Joaquin Delta, areas near a wild and scenic river). Additionally, projects subject to CPUC CEQA review frequently involve potentially significant impacts on cultural resources including historic resources and Tribal Cultural Resources. Under AB 52, the CEQA process is the platform for eliciting input from Tribes and engaging in Tribal consultation, which can be ongoing throughout the CEQA process.
    - The Farm Bureau asserts, "Proponents recommend adopting the parameters established for generation facilities approval at the California Energy Commission that was adopted in AB 205 in 2022 and align it to transmission facilities. It is mixing apples and oranges to do so. In contrast to reviewing and authorizing generation facilities which are reflective of willing buyers and sellers, transmission facility siting carries with it the power of eminent domain. Not only does that power impose land use impacts it also affects the compensation to be awarded to impacted stakeholders. … In our experience, the utilities' outreach to communities regarding potential infrastructure that carries with it the power of eminent domain significantly impacts how smoothly the approval process proceeds. … Until mandates for early effective outreach to communities are implemented, the processes should

not change." (*Opening Comments of the California Farm Bureau Federation Opposing the Joint Motion for Adoption of Phase 1 Settlement Agreement*, October 30, 2023, at 6-7)

- **Specifying that applications would be deemed complete after 30 days unless the utility is notified of deficiencies is consistent with Government Code Section 65943, but is already implicit in GO 131-D.** The settling parties propose to amend Sections IX.A.2 and IX.B.2 to specify that an application "shall be deemed complete (i) 30 days after submission of the application unless the utility is notified of deficiencies as set forth above; (ii) if the utility is notified of deficiencies as set forth above, then 30 days after the utility submits information in response to such notice unless the utility is notified within that 30 days that previously-identified deficiencies remain; or (iii) immediately upon the Commission's determination that any additional information requested by Commission staff has been provided, whichever comes first." This is consistent with Government Code Section 65943, which establishes that if a public agency does not make a written determination of application completeness and notify the applicant thereof within 30 days of receiving an application for a development project, the application and submitted materials shall be deemed complete. However, the existing version of GO 131-D already incorporates this requirement by reference in Section IX.A.2, stating, "The Commission shall issue a decision within the time limits prescribed by Government Code Sections 65920 et seq. (the Permit Streamlining Act)."

Staff do not recommend adopting Proposal 4 at this time, but recommend further consideration of the proposal, for the following reasons:

- **Implementing the Cal Advocates proposal would require further development of the expedited treatment that the prioritized projects would receive, among other issues.** Rather than delay the preparation of the Phase 2 staff proposal to develop a more extensive record on the Cal Advocates proposal, staff instead recommend that further consideration be given to the Cal Advocates proposal in a third phase or outside of the R.23-05-018 proceeding.
    - The CAISO asserts, "The CAISO has concerns about the impact of this proposal as it does not directly address issues around reforming permitting processes, risks undermining the planning and coordination done by the utilities and the CAISO, and inserts additional complexity and uncertainty in the application process. Although the proposal spends a significant amount of text on the process for prioritization, it is unclear what sort of expedited treatment the prioritized projects will receive. The CAISO suggests that the expedited treatment is the critical issue to deliberate, as the resource and transmission planning processes conducted by the state and local regulatory authorities and the CAISO serve to identify priority transmission projects." (*Reply Comments of the California Independent System Operator Corporation on Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 3) The CAISO further asserts, "This proposal is outside the scope of this proceeding because it does not look at the process of siting and permitting of transmission facilities, which is the scope of this proceeding." (Reply Comments of the California Independent System Operator Corporation on Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues, February 26, 2024, at 4)

  - In reply comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues, the Center for Biological Diversity and the POCF assert, "The Commission lacks jurisdiction to interfere with municipalities' constitutional rights and duties, including the right to enter into franchise agreements governing ROWs. … Absent major modifications to recognize the rights and duties of municipalities and other local jurisdictions, Cal Advocates' ROW sharing proposal reaches beyond Commission jurisdiction and must be rejected." (*Center for Biological Diversity and Protect Our Communities Foundation Reply Comments on Phase 2 Issues,* February 26, 2024, at 13)
  - The Acton Town Council expresses support for the Cal Advocates transmission project prioritization proposal and suggests that one or more workshops be convened to further develop the proposal with input from Energy Division staff: "The Acton Town Council believes that the bold, crosscutting recommendations which CalAdvocates proposes would be best initiated via one or more workshops which will facilitate collaboration and encourage dialogue among parties that have differing perspectives. The opportunities for dynamic interactions that are created by workshop events often provide superior results compared to static "review and comment" processes, particularly in the development of new programs. Accordingly, we suggest that one or more workshops be convened to "flesh out" CalAdvocates proposals. We also recommend that Energy Division staff participate in these workshops because they have considerable expertise in the strengths and flaws of the Commission's existing permit process." (*Reply Comments of the Acton Town Council on the Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 60)
- **Further developing the Cal Advocates proposal in Phase 2 of the R.23-05-018 proceeding could delay the Commission's resolution of Phase 2.**
  - American Clean Power states, "While we commend Cal Advocates for their analysis and illuminating breakdown of the average timeline to complete each phase of a project, we do not support the prioritization proposal. We are concerned that the time required to develop a new prioritization process would delay the Commission's resolution of Phase 2 and result in more uncertainty for the large majority of projects not prioritized." (*American Clean Power – California Reply Comments on Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 2)
- **A range of parties assert that prioritizing only policy-driven projects could exclude critical projects that are driven by reliability and economic benefits.**
  - In its response to R.23-05-018 Data Request 01, Question 6, PG&E asserts, "Rather than adding a process that would identify policy-driven transmission projects for prioritization, PG&E believes the CPUC should speed up the permitting process for all projects by avoiding duplication and increasing efficiencies in the CPUC permitting process." (*Pacific Gas and Electric Company GO 131-D Update and Amend OIR Rulemaking 23-05-018 Data Response* [Question 6], March 8, 2024, at 1)
  - In its reply comments on the ALJs' Ruling Inviting Comment on Phase 2 Issues, the CAISO asserts that it would be inappropriate to focus only on prioritizing policy-driven projects: "The proposal if pursued would also undermine the CAISO's transmission planning process

by focusing only on policy-driven projects, utilizing criterion already addressed in the CAISO's transmission planning process, and risking disrupting timelines. Policy-driven projects represent only a portion of the projects modeled and approved in the CAISO's transmission planning process. Reliability-driven projects are equally important to the whole network model and transmission plan that the CAISO evaluates and approves. … The proposal inappropriately omits projects driven by reliability or economic benefits and does not address when such projects would be eligible for Commission permitting under this framework. … The CAISO's robust modeling already serves as a prioritization of sorts by identifying required in-service dates for transmission projects. This new application prioritization framework risks impacting the system-wide plan the CAISO approves as it is unclear if and when de-prioritized projects would be eligible for permitting." (*Reply Comments of the California Independent System Operator Corporation on Administrative Law Judges' Ruling Inviting Comment on Phase 2 Issues*, February 26, 2024, at 5-6)

- In its response to R.23-05-018 Data Request 01, Question 6a, LS Power states, "LSPGC does not propose additional modifications in Phase 2 to prioritize reliability or policy-driven projects as both types of projects are equally important." (*LS Power Response Re: R.23-05-018 Data Request 01 – GO 131 Update Proceeding*, March 8, 2024, at 9)
- The Independent Energy Producers Association asserts, "IEP agrees that the Commission's approval of transmission projects needs to be streamlined, and Cal Advocates has developed a thorough and detailed proposal. However, it's not clear why policy-driven projects should be singled out for expedited treatment. As mentioned above, reliability-driven projects are essential to support the electrification of the transportation and building industry segments, and economic-driven projects can help support the affordability of electric service. What's needed is an approach that speeds up the development, approval, and construction of all varieties of the transmission projects required to maintain reliable and affordable electric service while supporting California's transition to a clean electric system." (*Reply Comments of the Independent Energy Producers Association on Phase 2 Issues*, February 26, 2024, at 9)

Appendices

The following appendices are included:

- **Appendix A. Proposed Revisions to GO 131-D to Address R.23-05-018 Phase 2 Issues (Redlines):** This appendix contains a redline version of GO 131-D detailing the proposed edits recommended by CPUC staff to address R.23-05-018 Phase 2 issues.
- **Appendix B. Proposed Revisions to GO 131-D to Address R.23-05-018 Phase 2 Issues (Clean):** This appendix contains a clean version of GO 131-D detailing the proposed edits recommended by CPUC staff to address R.23-05-018 Phase 2 issues.
- **Appendix C. Selected Party Responses to R.23-05-018 Data Request 01:** In addition to the rulings and comments that already exist in the record for the R.23-05-018 proceeding, this appendix contains selected responses to R.23-05-018 Data Request 01 upon which staff have relied to develop this staff proposal. CPUC Energy Division staff submitted R.23-05-018 Data Request 01 on January 29, 2024, and parties submitted responses on March 8, 2024.

Appendix A

Proposed Revisions to GO 131-D to Address R.23-05-018 Phase 2 Issues

(Redlines)

GENERAL ORDER NO. 131-~~D~~E
(Supersedes General Order No. 131-~~C~~D)

PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA

RULES RELATING TO THE PLANNING AND CONSTRUCTION OF ELECTRIC GENERATION, TRANSMISSION/POWER/DISTRIBUTION LINE FACILITIES AND SUBSTATIONS LOCATED IN CALIFORNIA.

~~**Adopted June 8, 1994. Effective July 8, 1994.**~~
~~**Decision 94-06-014**~~
~~**Modified August 11, 1995. Effective September 10, 1995.**~~
~~**Decision 95-08-038**~~
~~**Modified December 14, 2023. Effective December 14, 2023.**~~
~~**Decision 23-12-035**~~
Adopted [DATE] by Decision [XX-XX-XXX]

SECTION I. GENERAL

Pursuant to the provisions of Sections 451, 564, 701, 702, 761, 762, 768, 770, and 1001 of the Public Utilities Code:

IT IS HEREBY ORDERED that except as specifically provided herein, no electric public utility, now subject, or which hereafter may become subject, to the jurisdiction of this Commission, shall begin construction in this state of any new electric generating plant, or of the modification, alteration, or addition to an existing electric generating plant, or of electric transmission/power/distribution line facilities, or of new, upgraded, or modified substations without first complying with the provisions of this General Order.

For purposes of this General Order, the following definitions shall apply:

A. ~~a~~ A transmission line is a line designed to operate at or above 200 kilovolts (kV).

B. A power line is a line designed to operate between 50 and 200 kV.

C. A distribution line is a line designed to operate under 50 kV.

D. Construction does not include any installation of environmental monitoring equipment, or any soil or geological investigation, or work to determine feasibility of the use of the site for the proposed facilities, which do not result in a serious or major disturbance to an environmental resource.

E. An "existing electrical transmission facility" is an electrical transmission line, power line, or substation that has been constructed for operation at or above 50 kV within an existing transmission easement, right of way, or franchise agreement.

F. An "extension" is:

1. An increase in the length of an existing electrical transmission facility within existing transmission easements, rights-of-way, or franchise agreements; or

2. One of the following types of projects:

a. Generation tie-line (gen-tie) segments, i.e., the construction of a new transmission or power line from an existing electrical transmission facility to connect to a new energy storage or generation facility (i.e., the portion of the new line that will be owned by the transmission operator); or
b. Substation loop-ins, i.e., an incumbent utility looping existing transmission lines into and out of a new CAISO-approved third-party substation if the developer of the substation is required to file a CPCN application (because its scope includes a major new over-200 kV line as well as the substation) and the incumbent utility's scope is limited to looping several of its existing transmission lines into and out of the new substation-.

G. An "expansion" is an increase in the width, capacity, or capability of an existing electrical transmission facility, including but not limited to the following types of projects:

1. Rewiring or reconductoring to increase the capacity of an existing transmission line
2. Expanding the carrying capacity of existing towers
3. Converting a single-circuit transmission line to a double-circuit line to expand the quantity or capacity of the existing transmission line facilities

H. An "upgrade" is the replacement or alteration of existing electrical transmission facilities, or components thereof, to enhance the rating, voltage, capacity, capability, or quality of those facilities, including but not limited to the following types of projects:

1. Reconductoring existing lines to use conductors with greater power transfer capability and/or increased voltage levels, where

the reconductoring requires replacement of the existing supporting structures

2. Adding smart grid capabilities to an existing line, or other wildfire hardening measures
3. Installation of new mid-line series capacitors on a transmission line to support an increase in the power transfer capability of the line
4. Replacing existing support structures with new support structures of a different material and/or design
5. Adding battery energy storage systems to an existing substation, or expanding an existing substation to include battery energy storage systems
6. Replacing or adding equipment (e.g., circuit breakers, transformers) to a substation for the purpose of uprating the substation; or the uprating of individual components of a transmission line, power line, or substation

I. A "modification" is a change to an existing electrical transmission facility or equipment to serve a new or additional purpose without extending or expanding the physical footprint of the facility.

J. "Equivalent facilities or structures" are new power line facilities or supporting structures that are installed to replace existing power line facilities or supporting structures and that provide power transfer capability at no greater voltage than the facilities or structures being replaced.

K. "Accessories" are transmission line, power line, or substation equipment required for the safe and reliable operation of the transmission system, including but not limited to switches, connectors, relays, real-time monitoring equipment (e.g., telemetry, SCADA), and control shelters.

SECTION II. PURPOSE OF THIS GENERAL ORDER

The Commission has adopted these revisions to this General Order to be responsive to:

- The requirements of the California Environmental Quality Act (CEQA) (Public Resources (Pub. Res.) Code § 21000 et seq.) and Senate Bill No. 529 (Hertzberg), Stats. 2022;
- the need for public notice and the opportunity for affected parties to be heard by the Commission; and
- the obligations of the utilities to serve their customers in a timely and efficient manner.~~; and~~
- ~~the need to replace the present complaint treatment of under 200 kV projects with a new streamlined review mechanism.~~

SECTION III. NEED FOR COMMISSION AUTHORIZATION

~~For purposes of this General Order, construction does not include any installation of environmental monitoring equipment, or any soil or geological investigation, or work to determine feasibility of the use of the site for the proposed facilities, which do not result in a serious or major disturbance to an environmental resource.~~

A. Certificate of Public Convenience and Necessity (CPCN)

No electric public utility shall begin construction in this state of any of the following without first obtaining a certificate of public convenience and necessity (CPCN) from the Commission:

1. ~~-~~A~~a~~ny new electric generating plant having in aggregate a net capacity available at the busbar in excess of 50 megawatts (MW);

2. ~~,~~ T~~or of t~~he modification, alteration, or addition to an existing electric generating plant that results in a 50 MW or more net increase in the electric generating capacity available at the busbar of the existing plant; or

3. ~~, or~~M~~ of m~~ajor electric transmission line facilities which are designed for immediate or eventual operation at 200 kV or more ~~(~~, except for the following project types for which an electric public utility is authorized to file a permit to construct (PTC) application or claim an exemption under Section III.B:

   a. The replacement of existing power line facilities or supporting structures with equivalent facilities or structures~~,~~ ;
   b. ~~the~~ The minor relocation of existing power line facilities~~,~~ ;
   c. T~~t~~he conversion of existing overhead lines to underground~~,~~ ;~~or~~
   d. T~~t~~he placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built~~).~~; or ~~without this Commission's having first found that said facilities are necessary to promote the safety, health, comfort, and convenience of the public, and that they are required by the public convenience and necessity, resulting in the issuance of a certificate of public convenience and necessity (CPCN).~~
   e. ~~In lieu of complying with Section III.A, an electric public utility is authorized to file a permit to construct application or claim an exemption under Section III.B to~~ The construction of an extension, expansion, upgrade, or

other modification to an electric public utility's existing electrical transmission facilities, including electric transmission lines and substations within existing transmission easements, rights of way, or franchise agreements, irrespective of whether the electrical transmission facility is above a 200-kV voltage level.

B. Permit to Construct (PTC)

1. No electric public utility shall begin construction in this state of any of the following without first obtaining a PTC from the Commission:

a. ~~any~~ Any electric power line facilities or substations which are designed for immediate or eventual operation at any voltage between 50 kV and 200 kV ~~or~~,

b. ~~new~~ New or upgraded substations with high side voltage exceeding 50 kV~~,~~; or

c. The extension, expansion, upgrade, or other modification of existing electrical transmission facilities.

~~without this Commission having first authorized the construction of said facilities by issuance of a permit to construct in accordance with the provisions of Sections IX.B, X, and XI.B of this General Order. An upgraded substation is one in which there is an increase in substation land area beyond the existing utility-owned property or an increase in the voltage rating of the substation above 50 kV. Activities which increase the voltage of a substation to the voltage for which the substation has been previously rated are deemed to be substation modification projects and not substation upgrade projects.~~

~~1.~~2. ~~Compliance with Section IX.B~~A PTC is not required for:

~~a. power line facilities or substations with an in-service date occurring before January 1, 1996, which have been reported to the Commission in accordance with the Commission's decision adopting GO 131-D.~~

~~b.~~a. T~~t~~he replacement of existing power line facilities or supporting structures with equivalent facilities or structures.

~~c.~~b. T~~t~~he minor relocation of existing power line facilities up to 2,000 feet in length, or the intersetting of additional support structures between existing support structures.

~~d.~~c. T~~t~~he conversion of existing overhead lines to underground.

~~e.~~d. T~~t~~he placing of new or additional conductors, insulators, or their accessories on supporting structures already built.

~~f.~~e. P~~p~~ower lines or substations to be relocated or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (i.e., an Environmental Impact Report ~~(~~[EIR~~)~~], Mitigated Negative Declaration [MND], or Negative Declaration [ND]) finds no significant unavoidable environmental impacts caused by the proposed line or substation.

~~g.~~f. P~~p~~ower line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility easement, or in an existing right-of-way (ROW) containing existing power line facilities or substations; or power line facilities or substations in a utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, state, or local agencies for which a final ~~Negative Declaration or~~ EIR, MND, or ND finds no significant unavoidable environmental impacts.

~~h.~~g. T~~t~~he construction of projects that are statutorily or categorically exempt pursuant to § 15260 et seq. of the Guidelines adopted to implement ~~the~~ CEQA, 14 California Code of ~~California~~ Regulations § 15000 et seq. (CEQA Guidelines).

~~However, notice of the proposed construction of such facilities must be made in compliance with Section XI.B herein, except that such notice is not required for the construction of projects that are statutorily or categorically exempt pursuant to the CEQA Guidelines If a protest of the construction of facilities claimed by the utility to be exempt from compliance with Section IX.B is timely filed pursuant to Section XIII, construction may not commence until the Executive Director or Commission has issued a final determination.~~

~~2.~~ The foregoing exemptions shall not apply when ~~any of the conditions specified in CEQA Guidelines § 15300.2 exist:~~

~~a.~~ there is reasonable possibility that the activity may impact ~~on~~ an environmental resource of hazardous or critical concern where designated, precisely mapped and officially adopted pursuant to law by federal, state, or local agencies~~; or~~

~~3. the cumulative impact of successive projects of the same type in the same place, over time, is significant; or~~

3. ~~there is a reasonable possibility that the activity will have a significant effect on the environment due to unusual circumstances~~.

4. When a PTC is not required based on the exemptions above, notice of the proposed construction of such facilities must be made in compliance with Section X.B below, except that notice of the proposed construction of projects that are statutorily or categorically exempt pursuant to the CEQA Guidelines must be made through an information-only submittal pursuant to General Order 96-B or its successor regulation. The information-only submittal shall include the level of information that would be included in an advice letter but shall neither seek relief nor be subject to protest, pursuant to General Order 96-B, General Rule 6.2.

5. If a protest of the construction of facilities claimed by the utility to be exempt from compliance with Section X.B is timely filed pursuant to Section XI, construction may not commence until the Executive Director or Commission has issued a final determination.

C. Electric Distribution Lines and Other Substations

1. The construction of the following~~electric distribution (under 50 kV) line facilities, or substations with a high side voltage under 50 kV, or substation modification projects which increase the voltage of an existing substation to the voltage for which the substation has been previously rated within the existing substation boundaries,~~ does not require the issuance of a CPCN or ~~permit~~ PTC by this Commission nor discretionary permits or approvals by local governments. ~~However, to ensure safety and compliance with local building standards, the utility must first communicate with, and obtain the input of, local authorities regarding land use matters and obtain any non-discretionary local permits required for the construction and operation of these projects.~~

   a. Electric distribution (under 50 kV) line facilities;
   b. Substations with a high side voltage under 50 kV; or
   c. Substation modification projects which increase the voltage of an existing substation to the voltage for which the substation has been previously rated within the existing substation boundaries.

2. For the above projects, to ensure safety and compliance with

local building standards, the utility must first communicate with, and obtain the input of, local authorities regarding land use matters and obtain any non-discretionary local permits required for the construction and operation of these projects.

SECTION IV. UTILITY REPORT OF LOADS AND RESOURCES

Every electric public utility required to submit a report of loads and resources to the California Energy Commission (CEC) in accordance with Section 25300 et seq. of the Public Resources Code shall also furnish an electronic copy of its report to the Public Utilities Commission.

SECTION V. UTILITY REPORT OF PLANNED TRANSMISSION/ POWER LINE, AND SUBSTATION FACILITIES

A. Every electric public utility shall annually, on or before March 1, ~~furnish~~ submit to the Commission's Energy Division (Energy Division) an electronic copy of a ~~fifteen-year (15) forecast of~~report on planned transmission facilities ~~of 200 kV or greater~~ and ~~a five-year (5) forecast of~~ planned power line facilities and substations ~~of between 50 kV and 200 kV~~.

~~A.~~B. The annual report shall include:

1. A fifteen (15) year forecast of planned transmission facilities of 200 kV or greater and a five-year (5) forecast of planned power line facilities and substations of between 50 kV and 200 kV.
~~1.~~2. A list of transmission, power lines, and substations, arranged in chronological order by the planned service date, for which a CPCN or a ~~permit to construct~~PTC has been received, but which have not yet been placed in service.
~~2.~~3. A list of planned transmission, power lines, and substations of 50 kV or greater or planning corridors, arranged in chronological order by the planned service date, on which proposed route or corridor reviews are being undertaken with governmental agencies or for which applications have already been filed.
~~3.~~4. A list of planned transmission, power lines, and substations of 50 kV or greater or planning corridors, arranged in chronological order by the planned service date, on which planning corridor or route reviews have not started, which will be needed during the forecast periods.
~~B.~~5. For each transmission or power line route, substation, or planning corridor included in the above lists, the following information, if available, shall be included in the report:

~~1.~~• Planned operating date.

~~2.~~ • Transmission or power line name.
~~3.~~ • The terminal points (substation name and location).
~~4.~~ • Number of circuits.
~~5.~~ • Voltage – kV.
~~6.~~ • Normal and emergency continuous operating ratings – MVA.
~~7.~~ • Length in feet or miles.
~~8.~~ • Estimated cost in dollars as of the year the report is filed.
~~9.~~ • Cities and counties involved.
• Other comments.

C. Additionally, on a quarterly basis, every electric public utility shall organize a meeting with the Energy Division, unless Energy Division staff confirm in writing that such a meeting is not needed. At that meeting, the utility will present a briefing that includes the following:

1. The latest version of the required forecast of planned transmission lines, power lines, and substation facilities;
2. A forecast of any CPCN or PTC applications expected to be submitted within the following two years;
3. Estimated application filing dates for all CAISO-approved transmission plan projects; and
4. A summary of any projects that have been reprioritized since the last quarterly briefing.

SECTION VI. UTILITY REPORT OF INFORMATION REGARDING FINANCING OF NEW ELECTRIC GENERATING AND TRANSMISSION CAPACITY

Every electric public utility shall biennially, on or before June 1 of every odd numbered year, furnish a report to the Commission of the financial information designated in Appendix A ~~hereto~~; provided, however, that no public utility shall be required to submit such financial information if such utility does not plan for a fifteen-year (15) period commencing with the year in which the financial information is to be filed to (1) construct within the State of California any new electric generating plant having in the aggregate a net capacity in excess of 50 MW, ~~or~~ (2) modify, alter, or add to any existing electric generating plant that results in a 50 MW, or more, net increase in the electric generating capacity of an existing plant within the State of California, or (3) construct in California any electric transmission line facilities which are designed for immediate or eventual operation at any voltage in excess of 200 kV (except for the replacement or minor relocation of existing transmission line facilities, or the placing of additional conductors, insulators or their accessories on, or replacement of, supporting structures already built).

SECTION VII. ELECTRIC GENERATING AND RELATED TRANSMISSION

FACILITIES SUBJECT TO THE WARREN-ALQUIST ENERGY RESOURCES CONSERVATION AND DEVELOPMENT ACT

If an electric public utility proposes to construct electric generating and related transmission facilities which are subject to the power plant siting jurisdiction of the CEC as set forth in Section 25500 et seq. of the Public Resources Code, it shall comply with the following procedure:

A. In accordance with Public Resources Code Section 25519(c), Public Utilities Code Section 1001, and CEQA, this Commission's Rules of Practice and Procedure 2.4 and 2.5 do not apply to any application filed pursuant to this section.

B. Upon acceptance of an electric utility's Notice of Intent (NOI) filing by the CEC, the utility shall provide an electronic copy of the NOI to the Executive Director of this Commission.

C. When an electric utility files with the CEC an application for certification (AFC) to construct an electric generating facility pursuant to Section 25519 of the Public Resources Code and any AFC regulations of the CEC, it shall provide an electronic copy of the AFC, including a copy of the CEC's Final Report in the NOI proceeding for the facility, to the Executive Director of this Commission.

D. No later than 30 days after acceptance for filing of the AFC referred to above in Subsection C, the utility shall file with this Commission an application for a CPCN. The application shall comply with this Commission's Rules of Practice and Procedure and shall include the data and information set forth in Appendix B hereto. In complying with this provision, the utility may include portions of the CEC's Final Report in its NOI proceeding by attaching such portions as an appendix to its application filed with this Commission. The utility may also include portions of the AFC filed with the CEC by reference. A copy of the application shall be provided to the CEC and to every person, corporation, organization, or public agency that has intervened in the CEC's AFC proceeding.

E. No later than 30 days after the filing of the application, the Commission staff shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application. The utility shall correct any deficiencies within 60 days thereafter, or explain in writing to the Commission staff why it is unable to do so. It shall include in any such letter an estimate of when it will be able to correct the deficiencies. Upon correction of any deficiencies in the application, any public hearings which are necessary may be held on the application while the utility's AFC application is under process before the CEC. The

Commission may issue an interim decision on the application before the issuance by the CEC of a final decision in the AFC proceeding. However, any such interim decision shall not be final and shall be subject to review after the CEC issues its final decision in the AFC proceeding as prescribed in Public Resources Code Sections 25522 and 25530.

F. No later than 30 days after issuance of a certificate by the CEC in a final decision in the utility's AFC proceeding in accordance with Public Resources Code Sections 25209, 25522, and 25530 the Commission shall issue a decision on the application for a CPCN from this Commission, unless a later date for issuance of the decision is mutually agreed to by the Commission and the applicant, or is necessitated by conditions under Paragraph G.

G. If the CEC's certificate in the AFC proceedings sets forth requirements or conditions for the construction of the proposed electric generating facility which were not adequately considered in the proceeding before the Commission, and which will have a significant impact on the economic and financial feasibility of the project, or the rates of the utility, or on utility system reliability, the utility, or Commission staff, or any party, may request that the Commission hold a public hearing on such implications. Any such hearing, if granted, shall be initiated no later than 30 days after the filing of any such request. It is the intent of this Commission that a final decision shall be issued within 90 days after conclusion of the hearing, if held.

H. If judicial review of the CEC's issuance of a certificate in the AFC proceeding is sought in any court, the utility shall immediately notify this Commission and include a copy of the court filing.

SECTION VIII. ELECTRIC GENERATING FACILITIES NOT SUBJECT TO THE WARREN-ALQUIST ENERGY RESOURCES CONSERVATION AND DEVELOPMENT ACT

An electric public utility proposing to construct in this state new generation facilities in excess of 50 MW net capacity~~,~~ available at the busbar and related transmission facilities, or proposing to modify an existing generation facility and related transmission facilities in this state in order to increase the total generating capacity of the generation facility by 50 MW or more net capacity available at the busbar, shall file for a CPCN not less than 12 months prior to the date of a required decision by the Commission unless the Commission authorizes a shorter period for exceptional circumstances.

A. An application for a CPCN shall comply with this Commission's Rules of Practice and Procedure. In addition, it shall include or have attached to it the following:

1. The information and data set forth in Appendix B.
2. A statement of the reasons why and facts showing that the completion and operation of the proposed facility is necessary to promote the safety, health, comfort, and convenience of the public.
3. Safety and reliability information, including planned provisions for emergency operations and shutdowns.
4. A schedule showing the program for design, material acquisition, construction, and testing and operating dates.
5. Available site information, including maps and description, present, proposed, and ultimate development; and, as appropriate, geological, aesthetic, ecological, tsunami, seismic, water supply, population, and load center data, locations and comparative availability of alternate sites, and justification for adoption of the site selected.
6. Design information, including description of facilities, plan efficiencies, electrical connections to system, and description of control systems, including air quality control systems.
7. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.
~~6.~~8. Demonstration of compliance with other applicable Commission policies (e.g., the Environmental and Social Justice [ESJ] Action Plan).
9. A Proponent's Environment Assessment (PEA) on the environmental impact of the proposed facility and its operation so as to permit compliance with the requirements of CEQA and this Commission's Rules of Practice and Procedure 2.4 and 2.5. If a PEA is filed, it may include the data described in Items 1 through ~~6~~8, above.

B. An applicant may prepare and submit a draft version of an initial study or EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project if the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing, and provides the draft documents to Energy Division staff for review during the pre-filing period.

1. An applicant-prepared version of a draft CEQA document shall comply with the CEQA Guidelines, shall provide substantial

evidence for all findings and conclusions, and shall include issue-specific technical studies (e.g., biological resource studies, cultural resource studies).

~~7.~~2. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis. Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

C. No later than 30 days after the filing of the CPCN application, the Commission staff shall review it and notify the utility of any deficiencies in the information and data submitted in the application.

D. The utility shall correct any deficiencies within 60 days after notice ~~thereafter~~ or explain in writing to the Commission staff why it is unable to do so. The utility~~It~~ shall include in any such letter an estimate of when it will be able to correct the deficiencies.

~~B.~~E. Upon correction of any deficiencies in the application, ~~the~~ Commission staff shall determine whether CEQA applies, and if so, whether ~~a Negative Declaration or~~ an EIR, MND, or ND has been or will be prepared.~~,~~ T~~and t~~he process required by CEQA and Commission Rules 2.4 and 2.5 will be followed in addition to the Commission's standard decision-making process for applications. The Commission shall issue a decision within the time limits prescribed by Government Code Section 65920 et seq. (the Permit Streamlining Act).

SECTION IX. TRANSMISSION LINE, POWER LINE, AND SUBSTATION FACILITIES

A. Transmission Line Facilities of 200 kV and Over

1. An electric public utility desiring to build transmission line facilities in this state for immediate or eventual operation at or above 200 kV that require a CPCN under Section III.A, above, shall:

a. F~~f~~ile an application for a CPCN not less than 12 months prior to the date of a required decision by the Commission unless the Commission authorizes a shorter period because of exceptional circumstances;~~.~~

b. Provide written notice to Energy Division staff not less than 12 months prior to the filing of a CPCN application; and

c. Initiate pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than six (6) months prior to the filing of a CPCN application unless Energy Division staff authorize a shorter period in writing.

~~1.~~2. An application for a CPCN shall comply with this Commission's Rules of Practice and Procedure and shall also include the following:

a. A detailed description of the proposed transmission facilities, including the proposed transmission line route and alternative routes, if any; proposed transmission equipment; such as tower design and appearance, heights, conductor sizes, voltages, capacities, substations, switchyards, etc.; and a proposed schedule for certification, construction, and commencement of operation of the facilities.

b. A map of suitable scale of the proposed routing showing details of the right-of-way in the vicinity of settled areas, parks, recreational areas, scenic areas, and existing electrical transmission lines within one mile of the proposed route.

c. A statement of facts and reasons why the public convenience and necessity require the construction and operation of the proposed transmission facilities.

d. A detailed statement of the estimated cost of the proposed facilities.

e. Reasons for adoption of the route selected, including comparison with alternative routes, including the advantages and disadvantages of each.

f. A schedule showing the program of right-of-way acquisition and construction.

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

h. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

~~g.~~i. Demonstration of compliance with other applicable

Commission policies (e.g., the ESJ Action Plan).

~~h.~~j. A PEA or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and this Commission's Rules of Practice and Procedure, Rules 2.4 and 2.5. If a PEA is filed, it may include the data described in Items a through ~~g~~ i above. An applicant may file a draft version of an initial study or EIR instead of a PEA in compliance with the requirements in IX.C below.

3. No later than 30 days after the filing of the application, the Commission staff shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application.

4. The utility shall correct any deficiencies within 60 days ~~thereafter~~after notice~~,~~ or explain in writing to the Commission staff why it is unable to do so. The utility~~It~~ shall include in any such letter an estimate of when it will be able to correct the deficiencies.

~~2.~~5. Upon correction of any deficiencies in the application, the Commission staff shall determine whether CEQA applies, and if so, whether ~~a Negative Declaration or~~ an EIR, MND, or ND has been or will be prepared. T~~, and t~~he process required by CEQA and Commission Rules of Practice and Procedure 2.4 and 2.5 will be followed in addition to the Commission's standard decision-making process for applications. The Commission shall issue a decision within the time limits prescribed by Government Code Sections 65920 et seq. (the Permit Streamlining Act).

B. Transmission Line, Power Line, and Substation Facilities Designed to Operate Over 50 kV Which Are Not Included in Subsection A of this Section

1. Unless ~~exempt as specified in Section III herein, or~~ already included in an application before this Commission for a CPCN, an electric public utility desiring to build transmission line, power line, or substation facilities in this state for immediate or eventual operation over 50 kV, that require a ~~permit to construct~~PTC under Section III.B, above, shall:

a. F~~f~~ile an application for a ~~permit to construct~~PTC application not less than nine (9) months prior to the date of a required decision by the Commission;

b. Provide written notice to Energy Division staff not less than 12 months prior to the filing of a PTC application;~~,~~ and

c. Initiate pre-filing consultation with Energy Division staff pursuant to Section IX.B.1 not less than six (6) months prior to the filing of a PTC application unless ~~the Commission~~Energy Division staff authorize~~s~~ a shorter period ~~because of exceptional circumstances~~in writing.

~~1.~~2. An~~n~~ PTC application ~~for a permit to construct and the associated pre-filing consultation~~ shall comply with the Commission's Rules of Practice and Procedure, including Rules 2.4 and 2.5, and shall include the following:~~.~~

~~2. The application for a permit to construct shall also include the following:~~

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.

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.

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.

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

e. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

f. Demonstration of compliance with other applicable

Commission policies (e.g., the ESJ Action Plan).

~~e.~~g. A PEA or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and this Commission's Rules of Practice and Procedure 2.4 and 2.5. If a PEA is filed, it may include the data described in Items a through ~~d~~ f above. An applicant may file a draft version of an initial study or EIR instead of a PEA in compliance with the requirements in IX.C below.

3. ~~The above information requirements notwithstanding, a~~An application for a ~~permit to construct~~PTC 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.

4. No later than 30 days after the filing of the application for a ~~permit to construct~~PTC, the Energy Division shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application.

5. -W~~Thereafter, w~~ithin 30 days of notice of such notice, the utility shall correct any deficiencies or explain in writing to the Energy Division when it will be able to correct the deficiencies or why it is unable to do so.

~~4.~~6. -Upon correction of any deficiencies in the application, the Energy Division shall determine whether CEQA applies, and if so, whether ~~a Negative Declaration or~~ an EIR, MND, or ND must be prepared, and the process required by CEQA and the Commission's Rules of Practice and Procedure 2.4 and 2.5 will be followed.

~~5.~~7. If the Commission finds that a project properly qualifies for an exemption from CEQA, the Commission will grant the ~~permit to construct~~PTC.

~~6.~~8. If the Energy Division determines, after ~~completing its~~the completion of an initial study, that the project would not have a significant adverse impact on the environment, the Energy Division will prepare ~~a Negative Declaration~~an ND. If the initial study identifies potential significant effects, but the utility revises its proposal to avoid those effects, then the Commission could adopt ~~a Mitigated Negative Declaration~~an MND. ~~In either case, the Commission will grant the permit to~~

~~constructPTC.~~

~~7.~~9. If the initial study identifies potentially significant environmental effects, the Energy Division will prepare an EIR. The severity and nature of the effects, the feasibility of mitigation, the existence and feasibility of alternatives to the project, and the benefits of the project would all be considered by the Commission in deciding whether to grant or deny the ~~permit to construct~~PTC. ~~The Commission intends to issue a permit to construct or disapprove the project within eight months of accepting the application as complete. This time limit may be extended if necessary to comply with the requirements of CEQA, but may not exceed the time limits specified in CEQA (for the preparation of an EIR).~~

~~8. If no protests or requests for hearing are received (pursuant to Section XII), Energy Division staff shall be assigned and the Commission shall issue an ex parte decision on the application within the time limits prescribed by Government Code Section 65920 et seq. (the Permit Streamlining Act). If a protest or request for hearing is received, the matter shall be assigned to an administrative law judge, and the Commission shall issue a decision on the application within the time limits prescribed by the Permit Streamlining Act.~~

C. Preparation of CEQA Documents and Commission Decision

1. An applicant may elect to prepare and submit a draft version of an initial study or a draft version of an EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project provided that the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing, and provides the draft documents to Energy Division staff for review during the pre-filing period.

   a. An applicant-prepared version of a draft CEQA document shall comply with the CEQA Guidelines, shall provide substantial evidence for all findings and conclusions, and shall include issue-specific technical studies (e.g., biological resource studies, cultural resource studies).
   b. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis.

Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

2. Where the electric project proposed in a CPCN or PTC application has been evaluated and approved by the California Independent System Operator (CAISO) in a transmission plan prepared in accordance with the CAISO tariff approved by the Federal Energy Regulatory Commission (FERC):

   a. The statement of objectives required by 14 Cal. Code Regs. § 15124(b) in a CEQA document for the proposed project should consider the underlying purpose and project benefits of the proposed project as stated in the relevant CAISO transmission plan.

   b. In a proceeding evaluating the issuance of a CPCN for a proposed transmission project, if all the provisions of Section IX.C.2 are satisfied, the Commission shall establish a rebuttable presumption in favor of a CAISO governing board-approved finding that such project is needed.

3. Section IX.C.2.b shall apply only to proceedings where:

   a. The CAISO governing board has made explicit findings regarding the need for the proposed transmission project and has determined that the proposed project is the most cost-effective transmission solution.

   b. The CAISO is a party to the proceeding.

   c. The CAISO governing board-approved need evaluation is submitted to the Commission within sufficient time to be included within the scope of the proceeding.

   d. There has been no substantial change to the scope, estimated cost, or timeline of the proposed transmission project as approved by the CAISO governing board.

~~SECTION X. POTENTIAL EXPOSURE TO ELECTRIC AND MAGNETIC FIELDS (EMF)~~

~~Applications for a CPCN or Permit to Construct shall describe the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields generated by the proposed facilities, in compliance with Commission order. This information may be included in the PEA required by Rule 2.4 of the Commission's Rules of Practice and Procedure.~~

SECTION X~~I~~. NOTICE

A. Applications for a CPCN or ~~Permit to Construct~~PTC

Notice of the filing of each application for a CPCN required by Section III.A of this General Order and of the filing of each application for a ~~permit to construct~~PTC required by Section III.B of this General Order, shall be given by the electric public utility within ten days of filing the application:

1. By direct mail to:

   a. The planning commission and the legislative body for each county or city in which the proposed facility would be located, the CEC, 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 Health Care Services, the State Water Resources Control Board, the Air Resources Board, and other interested parties having requested such notification.

   ~~a.~~b. ~~The utility shall also give notice to t~~The following agencies and subdivisions in whose jurisdiction the proposed facility would be located: the Air Pollution Control District, the California Regional Water Quality Control Board, the California Coastal Commission, the State Department of Transportation's District Office, and any other State or Federal agency which would have jurisdiction over the proposed construction; and

   ~~b.~~c. All owners of land on which the proposed facility would be located and owners of property within 300 feet of the right-of-way as determined by the most recent local assessor's parcel roll available to the utility at the time notice is sent; and

2. By advertisement, not less than once a week, two weeks successively, in a newspaper or newspapers of general circulation that serves the county or counties in which the proposed facilities will be located, the first publication to be not later than ten days after filing of the application; and

3. By posting a notice on-site and off-site where the project would be located.

   A copy of the notice shall be provided to the Commission's Public Advisor and the Energy Division on the same day it is mailed. A declaration of mailing and posting as required by this subsection shall be filed with the Commission within five (5) days of completion.

A copy of each application for electric generation facilities shall be served on the Executive Director of the Energy Commission. If applicable, a copy shall be served on the Executive Director of the Coastal Commission. If applicable, a copy shall be served on the Executive Director of the S.F. Bay Conservation and Development Commission. Upon request by any public agency, the applicant shall provide a copy of its application to said public agency. A copy of the application shall be posted on the utility's website.

B. Transmission Line, Power Line, and Substation Facilities Designed to Operate Over 50 kV Which Are Not Included in Subsection A of this Section

The utility shall give notice of the construction of any transmission line, power line, or substation facilities designed to operate over 50kV deemed exempt pursuant to Section III.B.1 herein, not less than 30 days before the date when construction is intended to begin by:

1. Direct mail to the planning director for each county or city in which the proposed facility would be located and the Executive Director of the Energy Commission; and
2. Advertisement, not less than once a week, two weeks successively, in a newspaper or newspapers of general circulation that serves the county or counties in which the proposed facility would be located, the first publication to be not later than 45 days before the date when construction is intended to begin; and
3. By posting a notice on-site and off-site where the project would be located.
4. Filing an ~~informational~~ advice letter with the Energy Division in accordance with General Order 96-B, which includes a copy and distribution list of the notices required by items 1-3 herein. On the same day, a copy of the advice letter must be delivered to the Commission's Public Advisor.

C. Contents of Notices

Each utility shall consult with the Energy Division and Commission's Public Advisor to develop and approve a standard for the notice required by subsections A and B, which shall contain, at a minimum, the following information:

1. The Application Number assigned by the Commission or the Advice Letter Number assigned by the utility; and
2. A concise description of the proposed construction and facilities, its purpose and its location in terms clearly understandable to the average reader; and

3. A summary of the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields generated by the proposed facilities, in compliance with Commission order; and

4. Instructions on obtaining or reviewing a copy of the application, including the Proponent's Environmental Assessment or available equivalent, from the utility; and

5. The applicable procedure for protesting the application or advice letter, as defined in Sections XI~~I~~ and XII~~I~~, including the grounds for protest, when the protest period expires, delivery addresses for the Commission's Docket Office, Energy Division, and the applicant and how to contact the Commission's Public Advisor for assistance in filing a protest.

SECTION XI~~I~~. PROTEST AND REQUEST FOR PUBLIC HEARINGS

Pursuant to the Commission's Rules of Practice and Procedure, Rule 2.6, those to whom notice has been sent under Section X~~I~~.A ~~hereof~~ and any other person entitled under the Commission's Rules of Practice and Procedure to participate in a proceeding for a CPCN or a ~~permit to construct~~PTC may, within 30 days after the notice was mailed or published, object to the granting in whole or in part of the authority sought by the utility and request that the Commission hold hearings on the application. Any such protest shall be filed in accordance with Rule 2.6. If the Commission, as a result of its preliminary investigation after such requests, determines that public hearings should be held, notice shall be sent to each person who is entitled to notice or who has requested a hearing.

The Commission's Public Advisor shall provide information to assist the public in submitting such protests.

SECTION XII~~I~~. PROTEST TO REQUIRE THE UTILITY TO FILE FOR ~~PERMIT TO CONSTRUCT~~PTC

Those to whom notice has been given under Section X~~I~~.B ~~hereof~~ and any other person or entity entitled to participate in a proceeding for a ~~permit to construct~~PTC may, within 20 days after the notice was mailed and published, contest any intended construction for which exemption is claimed by the utility from the requirements of Section III.B if such persons or entities have valid reason to believe that any of the conditions described in Section III.B.2 exist or the utility has incorrectly applied an exemption as defined in Section III~~ herein~~. The protest shall be filed with the Energy Division, specifying the relevant utility advice letter number, in accordance with General Order 96-B, Sections 3.11, 7.4.1, and 7.4.2. On the same date a protest is filed with the Commission, the protestant shall serve a copy on the subject utility by mail. The utility shall respond within five business days of receipt and serve copies of its response on each protestant and the Energy Division. Construction shall not commence until the Executive Director has ~~issued an Executive~~disposed of the protest

~~Resolution~~.

Within 30 days after the utility has submitted its response, the Executive Director, after consulting with the Energy Division, shall issue a~~n Executive Resolution~~ disposition letter on whether: the utility is to file an application for a ~~permit to construct~~PTC, or the protest is dismissed for failure to state a valid reason. Also, the Executive Director shall state the reasons for granting or denying the protest and provide a copy of ~~each Executive Resolution~~ the disposition letter to the Commission's Public Advisor.

The utility, any persons that filed a protest to the advice letter, or other persons or entities (to the extent authorized by General Order 96-B or its successor regulation) may request Commission review of the Executive Director's or Energy Division's disposition of an advice letter, pursuant to General Order 96-B, General Rule 7.6.3 (or a successor regulation).

The Commission's Public Advisor shall provide information to assist the public in submitting such protests.

SECTION ~~XIV~~XIII. COMPLAINTS AND PREEMPTION OF LOCAL AUTHORITY

A. Complaints may be filed with the Commission for resolution of any alleged violations of this General Order pursuant to Article 4 of the Commission's Rules of Practice and Procedure. A complaint which does not allege that the matter has first been brought to the staff for informal resolution may be referred to the staff to attempt to resolve the matter informally (Rule of Practice and Procedure 4.2(b)).

B. This General Order clarifies that local jurisdictions acting pursuant to local authority are preempted from regulating electric power line projects, distribution lines, substations, or electric facilities constructed by public utilities subject to the Commission's jurisdiction. However, in locating such projects, the public utilities shall consult with local agencies regarding land use matters. In instances where the public utilities and local agencies are unable to resolve their differences, the Commission shall set a hearing no later than 30 days after the utility or local agency has notified the Commission of the inability to reach agreement on land use matters.

C. Public agencies and other interested parties may contest the construction of under-50-kV distribution lines and electric facilities by filing a complaint with the Commission pursuant to Article 4 of the Commission's Rules of Practice and Procedure.

SECTION XIV. STATE AGENCY REVIEW OF ELECTRIC GENERATING AND RELATED TRANSMISSION FACILITIES NOT SUBJECT TO THE WARREN-ALQUIST ENERGY RESOURCES CONSERVATION AND DEVELOPMENT ACT

Nothing in this order shall be construed to preempt or otherwise limit the jurisdiction of state agencies other than this Commission to exercise the full range of their jurisdiction under state or federal law over facilities subject to this order.

A coastal development permit shall be obtained from the Coastal Commission for development of facilities subject to this order in the coastal zone.

SECTION XV~~I~~. CEQA COMPLIANCE

Construction of facilities for which a CPCN or ~~permit to construct~~PTC is required pursuant to this General Order shall not commence without either a finding that it can be seen with certainty that there is no possibility that the construction of those facilities may have a significant effect on the environment or that the project is otherwise exempt from CEQA, or the adoption of a final EIR, MND, or ~~Negative Declaration~~ND. Where authority must be granted for a project by this Commission, applicants shall comply with Rules 2.4 and 2.5 of the Commission's Rules of Practice and Procedure. This latter requirement does not apply to applications covering generating and related transmission facilities for which a certificate authorizing construction of the facilities has been or will also be issued by the CEC. For all issues relating to the siting, design, and construction of electric generating plant or transmission lines as defined in Sections VIII and IX.A herein or electric power lines or substations as defined in Section IX.B herein, the Commission will be the Lead Agency under CEQA, unless a different designation has been negotiated between the Commission and another state agency consistent with CEQA Guidelines § 15051(d).

Pursuant to Sections 15107 and 15110 of the CEQA Guidelines, the Commission strives to complete Proposed Final MNDs or NDs for projects without federal agency involvement within 270 days or sooner from the date the PTC or CPCN application is deemed complete. Pursuant to Sections 15108 and 15110 of the CEQA Guidelines, the CPUC would strive to complete Proposed EIRs for projects without federal agency involvement within 455 days or sooner from the date that the application is deemed complete. Sections 15109 and 15110 of the CEQA Guidelines shall apply regarding the suspension of time periods and projects with federal involvement.

Projects requiring CPUC approval of a PTC that qualify for an MND or ND and have no federal agency involvement could involve completion of CEQA review within 270 days. In accordance with Section 15070 of the CEQA Guidelines, CPUC shall prepare or have prepared a proposed ND or MND for a project when:

A. The initial study shows that there is no substantial evidence (as defined in Section 15384 of the CEQA Guidelines), in light of the whole record before the agency, that the project may have a significant effect on the environment, or

B. The initial study identifies potentially significant effects, but:

1. Revisions in the project plans or proposals made by, or agreed to by the applicant before a proposed mitigated negative declaration and initial study are released for public review would avoid the effects or mitigate the effects to a point where clearly no significant effects would occur, and
2. There is no substantial evidence, in light of the whole record before the agency, that the project as revised may have a significant effect on the environment.

Appendix A - General Order No. 131-D

INFORMATION TO BE INCLUDED IN THE UTILITY REPORT
REGARDING FINANCING OF NEW ELECTRIC
GENERATING CAPACITY ~~AND~~, TRANSMISSION LINE, AND
POWER LINE PROJECTS

I. A statement, detailing the economic assumptions used to project all construction expenditures and annual operating costs, including the methodology, assumptions, and sources and authorities associated therewith for a fifteen-year (15) period commencing with the year in which the report is filed, for each of the following:

A. Operating Revenues
1. Electric
2. Gas, if applicable
3. Miscellaneous
4. Total

B. Capital Costs to be Added to Rate Base
1. Direct Material Costs
2. Direct Labor Costs
3. Allowance for Funds Used During Construction (AFUDC)
4. Construction Work in Progress (CWIP) added to rate base due to incentive
5. Overhead
6. Others

C. Long-Term Capital Costs
1. Rate of Return
   - Return on Equity (ROE) (common stock)
   - Return on Preferred Stock
   - Long-Term Debt
2. Depreciation
3. Taxes on ROE

~~B.~~D. Operating and Maintenance (O&M) and Administrative and General (A&G) Expenses and Taxes
1. Cost of Electric Energy
2. Cost of Gas sold, if applicable
3. Transmission and Distribution
4. Maintenance
5. ~~Depreciation~~Insurance
6. Taxes on Income
7. Property and Other Taxes

8. Other
9. Total

~~C.~~E. Operating Income

~~D.~~F. Other Income and Deductions
~~1. Allowance for Equity Funds Used During Construction~~
~~2.~~1. Gains on Bonds Purchased for Sinking Fund
~~3.~~2. Subsidiary Income
~~4.~~3. Other – Net
~~5.~~4. Total

~~E.~~G. Income Before Interest Charges

~~F.~~H. Interest Charges
1. Short-term
2. Long-term
3. Less Allowance for Borrowed Funds Used During Construction
4. Total

~~G.~~I. Net Income

~~H.~~J. Preferred Dividend Requirement

~~I.~~K. Earnings Available for Common Stock

~~J.~~L. Average Number of Shares of Common Stock Outstanding (Thousands)

~~K.~~M. Earnings Per Share of Common Stock

~~L.~~N. Dividends Per Share of Common Stock
1. Declared Basis
2. Paid Basis

II. An estimate for each of the following capital requirements items for each year for a fifteen-year period commencing with the year in which the report is filed:

A. Construction expenditures by year, including materials, labor, overhead, and AFUDC, broken down by:
1. Generation projects over $100 million, including those, if any, located out-of-state

a. Busbar, including switchyard, expenditures

2. All other generation projects, including those, if any, located out-of-state

a. Busbar, including switchyard, expenditures

b. Associated transmission expenditures

3. Non-generation transmission expenditures
4. Distribution expenditures
5. Other expenditures

Breakdown of each item in 1 above into the following elements:

Directs	(M&S + Labor)	Indirects	AFDC	Total
	$	$	$	$

B. Bond retirements, sinking fund retirements, etc.

C. Investments in subsidiary companies

III. An estimate for each of the following items for each year for a fifteen-year period commencing with the year in which the report is filed:

A. Capital balances as of January 1

B. Capital ratios as of January 1

C. Imbedded costs of debt and preferred stock

D. Debt, preferred and common stock issues:
1. Amount ($ and shares)
2. Yield and cost of each issue

E. Income tax information
1. Tax operating expense
2. State tax depreciation
3. Federal tax depreciation
4. ITC or other credits available and used

F. Short-term debt balances

G. Annual equivalent rate used to compute the Allowance for Funds Used During Construction

IV. Data showing the estimated Results of Operation for electric utility operations for each year for a fifteen-year (15) period, commencing with the year in which the report is filed, in the format set forth below:

A. Kilowatt-hour Sales
1. Total
2. Residential

B. Average Price (¢/kWh)

C. Number of Residential Customers

D. Gross Revenue – Total
   1. Base Rates
   2. ECAC Rates
   3. ECAC Rate Increases
   4. Non-ECAC Rate Increases
   5. Misc. Operating Revenues

E. Operating Expenses – Total
   1. Production – Fuel and Purchased Power – Total
      a. Oil
      b. Gas
      c. Nuclear
      d. Coal
      e. Geothermal
      f. Combined Cycle
      g. Purchased Power
      h. Other (explain)

   2. Production O&M (non-fuel)
   3. Transmission
   4. Distribution
   5. Customer Accounts
   6. A&G
   7. Depreciation & Amortization
   8. Taxes – Total
      a. State Income
      b. Federal Income
      c. Ad Valorem
      d. Other

   9. Other (explain)

F. Net Operating Income

G. Rate Base (Weighted Average)

H. Rate of Return

I. Net-to-Gross Multiplier

V. For those electric utilities which also operate other public utility departments, such as natural gas, steam, and water service, an estimate of the following financial information by department for each year for a fifteen-year (15) period, commencing with the year in which the report is filed. Any separate utility operation that contributes to less than one (1) percent of the utility's total gross operating revenues may be excluded.

A. Gross Revenue
B. Operating Expenses
C. Net Operating Income
D. Rate Base (Weighted Average)
E. Rate of Return

VI. The following variables will be provided by the staff of the Public Utilities Commission for use by the utility in generating certain financial information required by Appendix A:

A. Return on Common Equity
B. Dividend Yield
C. Market to Book Ratio
D. Cost of Long-Term Debt (including incremental cost)
E. Cost of Preferred Stock (including incremental cost)
F. Common Stock Price
G. Annual equivalent rate used to compute the Allowance for Funds Used During Construction

These variables will be furnished 60 days before the annual utility report is due and will be developed by the staff based on its independent expertise.

Appendix B – General Order No. 131-D

INFORMATION TO BE INCLUDED IN AN APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ELECTRIC GENERATING FACILITIES

I. A detailed description of the proposed generating facility and related facilities and the manner in which the same will be constructed, including the type, size, fuel capabilities, and capacity of the generating facilities.

II. A map of suitable scale showing the location of the proposed power plant and related facilities, and a description of the location of the proposed power plant and related facilities.

III. A listing of federal, state, regional, county, district, or municipal agencies from which approvals either have been obtained or will be required covering various aspects of the proposed facility, including any franchises and health and safety permits and the planned schedule for obtaining those approvals not yet received.

IV. Load and resource data setting forth recorded and estimated loads (energy and demands), available capacity and energy, and margins for 5 years actual and 20 years estimated on the same basis, as reported to the CEC including a statement of the compatibility of the proposed generating facility with the most recent biennial report issued by the CEC pursuant to Section 25309 of the Public Resources Code.

V. Existing rated and effective operating capacity of generating plants and the planned additions for a ten-year (10) period.

VI. Estimated cost information, including plant costs by accounts, all expenses by categories, including fuel costs, plant service life, capacity factor, total generating cost per kWh (1) at plant, and (2) including related transmission, levelized for the economic life of the plant, year by year for the 12 years commencing with the date of commercial operation of the plant, and comparative costs of other alternatives considered on a levelized or year-by-year basis depending upon availability of data. Estimated capital and operating costs of power to be generated by the proposed plant for all competitive fuels which may be lawfully used in the proposed plant. When substantially the same data are prepared for utility planning purposes they may be used to satisfy all or any portion of these requirements.

VII. For any nuclear plant a statement indicating that the requisite safety and other license approvals have been obtained or will be applied for.

VIII. Such additional information and data as may be necessary for a full understanding and evaluation of the proposal.

(End of Appendix)

Appendix B

Proposed Revisions to GO 131-D to Address R.23-05-018 Phase 2 Issues

(Clean)

GENERAL ORDER NO. 131-E
(Supersedes General Order No. 131-D)

PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA

RULES RELATING TO THE PLANNING AND CONSTRUCTION OF ELECTRIC GENERATION, TRANSMISSION/POWER/DISTRIBUTION LINE FACILITIES AND SUBSTATIONS LOCATED IN CALIFORNIA.

Adopted [DATE] by Decision [XX-XX-XXX]

SECTION I. GENERAL

Pursuant to the provisions of Sections 451, 564, 701, 702, 761, 762, 768, 770, and 1001 of the Public Utilities Code:

IT IS HEREBY ORDERED that except as specifically provided herein, no electric public utility, now subject, or which hereafter may become subject, to the jurisdiction of this Commission, shall begin construction in this state of any new electric generating plant, or of the modification, alteration, or addition to an existing electric generating plant, or of electric transmission/power/distribution line facilities, or of new, upgraded, or modified substations without first complying with the provisions of this General Order.

For purposes of this General Order, the following definitions shall apply:

A. A transmission line is a line designed to operate at or above 200 kilovolts (kV).

B. A power line is a line designed to operate between 50 and 200 kV.

C. A distribution line is a line designed to operate under 50 kV.

D. Construction does not include any installation of environmental monitoring equipment, or any soil or geological investigation, or work to determine feasibility of the use of the site for the proposed facilities, which do not result in a serious or major disturbance to an environmental resource.

E. An "existing electrical transmission facility" is an electrical transmission line, power line, or substation that has been constructed for operation at or above 50 kV within an existing transmission easement, right of way, or franchise agreement.

F. An "extension" is:

1. An increase in the length of an existing electrical transmission facility within existing transmission easements, rights-of-way, or franchise agreements; or

2. One of the following types of projects:

   a. Generation tie-line (gen-tie) segments, i.e., the construction of a new transmission or power line from an existing electrical transmission facility to connect to a new energy storage or generation facility (i.e., the portion of the new line that will be owned by the transmission operator); or
   b. Substation loop-ins, i.e., an incumbent utility looping existing transmission lines into and out of a new CAISO-approved third-party substation if the developer of the substation is required to file a CPCN application (because its scope includes a major new over-200 kV line as well as the substation) and the incumbent utility's scope is limited to looping several of its existing transmission lines into and out of the new substation.

G. An "expansion" is an increase in the width, capacity, or capability of an existing electrical transmission facility, including but not limited to the following types of projects:

1. Rewiring or reconductoring to increase the capacity of an existing transmission line
2. Expanding the carrying capacity of existing towers
3. Converting a single-circuit transmission line to a double-circuit line to expand the quantity or capacity of the existing transmission line facilities

H. An "upgrade" is the replacement or alteration of existing electrical transmission facilities, or components thereof, to enhance the rating, voltage, capacity, capability, or quality of those facilities, including but not limited to the following types of projects:

1. Reconductoring existing lines to use conductors with greater power transfer capability and/or increased voltage levels, where the reconductoring requires replacement of the existing supporting structures
2. Adding smart grid capabilities to an existing line, or other wildfire hardening measures
3. Installation of new mid-line series capacitors on a transmission line to support an increase in the power transfer capability of the

line

4. Replacing existing support structures with new support structures of a different material and/or design
5. Adding battery energy storage systems to an existing substation, or expanding an existing substation to include battery energy storage systems
6. Replacing or adding equipment (e.g., circuit breakers, transformers) to a substation for the purpose of uprating the substation; or the uprating of individual components of a transmission line, power line, or substation

I. A "modification" is a change to an existing electrical transmission facility or equipment to serve a new or additional purpose without extending or expanding the physical footprint of the facility.

J. "Equivalent facilities or structures" are new power line facilities or supporting structures that are installed to replace existing power line facilities or supporting structures and that provide power transfer capability at no greater voltage than the facilities or structures being replaced.

K. "Accessories" are transmission line, power line, or substation equipment required for the safe and reliable operation of the transmission system, including but not limited to switches, connectors, relays, real-time monitoring equipment (e.g., telemetry, SCADA), and control shelters.

SECTION II. PURPOSE OF THIS GENERAL ORDER

The Commission has adopted these revisions to this General Order to be responsive to:

- The requirements of the California Environmental Quality Act (CEQA) (Public Resources (Pub. Res.) Code § 21000 et seq.) and Senate Bill No. 529 (Hertzberg), Stats. 2022;
- the need for public notice and the opportunity for affected parties to be heard by the Commission; and
- the obligations of the utilities to serve their customers in a timely and efficient manner.

SECTION III. NEED FOR COMMISSION AUTHORIZATION

A. Certificate of Public Convenience and Necessity (CPCN)

No electric public utility shall begin construction in this state of any of the following without first obtaining a certificate of public convenience and necessity (CPCN) from the Commission:

1. Any new electric generating plant having in aggregate a net capacity available at the busbar in excess of 50 megawatts (MW);

2. The modification, alteration, or addition to an existing electric generating plant that results in a 50 MW or more net increase in the electric generating capacity available at the busbar of the existing plant; or

3. Major electric transmission line facilities which are designed for immediate or eventual operation at 200 kV or more, except for the following project types for which an electric public utility is authorized to file a permit to construct (PTC) application or claim an exemption under Section III.B:

   a. The replacement of existing power line facilities or supporting structures with equivalent facilities or structures;
   b. The minor relocation of existing power line facilities;
   c. The conversion of existing overhead lines to underground;
   d. The placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built; or
   e. The construction of an extension, expansion, upgrade, or other modification to an electric public utility's existing electrical transmission facilities, including electric transmission lines and substations within existing transmission easements, rights of way, or franchise agreements, irrespective of whether the electrical transmission facility is above a 200-kV voltage level.

B. Permit to Construct (PTC)

1. No electric public utility shall begin construction in this state of any of the following without first obtaining a PTC from the Commission:

   a. Any electric power line facilities or substations which are designed for immediate or eventual operation at any voltage between 50 kV and 200 kV,
   b. New or upgraded substations with high side voltage exceeding 50 kV; or
   c. The extension, expansion, upgrade, or other modification of existing electrical transmission facilities.

2. A PTC is not required for:

a. The replacement of existing power line facilities or supporting structures with equivalent facilities or structures.
b. The minor relocation of existing power line facilities up to 2,000 feet in length, or the intersetting of additional support structures between existing support structures.
c. The conversion of existing overhead lines to underground.
d. The placing of new or additional conductors, insulators, or their accessories on supporting structures already built.
e. Power lines or substations to be relocated or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (i.e., an Environmental Impact Report [EIR], Mitigated Negative Declaration [MND], or Negative Declaration [ND]) finds no significant unavoidable environmental impacts caused by the proposed line or substation.
f. Power line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility easement, or in an existing right-of-way (ROW) containing existing power line facilities or substations; or power line facilities or substations in a utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, state, or local agencies for which a final EIR, MND, or ND finds no significant unavoidable environmental impacts.
g. The construction of projects that are statutorily or categorically exempt pursuant to § 15260 et seq. of the Guidelines adopted to implement CEQA, 14 California Code of Regulations § 15000 et seq. (CEQA Guidelines).

3. The foregoing exemptions shall not apply when there is reasonable possibility that the activity may impact an environmental resource of hazardous or critical concern where designated, precisely mapped and officially adopted pursuant to law by federal, state, or local agencies.

4. When a PTC is not required based on the exemptions above, notice of the proposed construction of such facilities must be made in compliance with Section X.B below, except that notice of the proposed construction of projects that are statutorily or categorically exempt pursuant to the CEQA Guidelines must be made through an information-only submittal pursuant to General Order 96-B or its successor regulation. The information-only submittal shall include the level of information that would be

included in an advice letter but shall neither seek relief nor be subject to protest, pursuant to General Order 96-B, General Rule 6.2.

5. If a protest of the construction of facilities claimed by the utility to be exempt from compliance with Section X.B is timely filed pursuant to Section XI, construction may not commence until the Executive Director or Commission has issued a final determination.

C. Electric Distribution Lines and Other Substations

1. The construction of the following does not require the issuance of a CPCN or PTC by this Commission nor discretionary permits or approvals by local governments.

   a. Electric distribution (under 50 kV) line facilities;
   b. Substations with a high side voltage under 50 kV; or
   c. Substation modification projects which increase the voltage of an existing substation to the voltage for which the substation has been previously rated within the existing substation boundaries.

2. For the above projects, to ensure safety and compliance with local building standards, the utility must first communicate with, and obtain the input of, local authorities regarding land use matters and obtain any non-discretionary local permits required for the construction and operation of these projects.

SECTION IV. UTILITY REPORT OF LOADS AND RESOURCES

Every electric public utility required to submit a report of loads and resources to the California Energy Commission (CEC) in accordance with Section 25300 et seq. of the Public Resources Code shall also furnish an electronic copy of its report to the Public Utilities Commission.

SECTION V. UTILITY REPORT OF PLANNED TRANSMISSION/ POWER LINE, AND SUBSTATION FACILITIES

A. Every electric public utility shall annually, on or before March 1, submit to the Commission's Energy Division (Energy Division) an electronic copy of a report on planned transmission facilities and planned power line facilities and substations.

B. The annual report shall include:

1. A fifteen (15) year forecast of planned transmission facilities of

200 kV or greater and a five-year (5) forecast of planned power line facilities and substations of between 50 kV and 200 kV.

2. A list of transmission, power lines, and substations, arranged in chronological order by the planned service date, for which a CPCN or a PTC has been received, but which have not yet been placed in service.
3. A list of planned transmission, power lines, and substations of 50 kV or greater or planning corridors, arranged in chronological order by the planned service date, on which proposed route or corridor reviews are being undertaken with governmental agencies or for which applications have already been filed.
4. A list of planned transmission, power lines, and substations of 50 kV or greater or planning corridors, arranged in chronological order by the planned service date, on which planning corridor or route reviews have not started, which will be needed during the forecast periods.
5. For each transmission or power line route, substation, or planning corridor included in the above lists, the following information, if available, shall be included in the report:

   - Planned operating date.
   - Transmission or power line name.
   - The terminal points (substation name and location).
   - Number of circuits.
   - Voltage – kV.
   - Normal and emergency continuous operating ratings – MVA.
   - Length in feet or miles.
   - Estimated cost in dollars as of the year the report is filed.
   - Cities and counties involved.
   - Other comments.

C. Additionally, on a quarterly basis, every electric public utility shall organize a meeting with the Energy Division, unless Energy Division staff confirm in writing that such a meeting is not needed. At that meeting, the utility will present a briefing that includes the following:

1. The latest version of the required forecast of planned transmission lines, power lines, and substation facilities;
2. A forecast of any CPCN or PTC applications expected to be submitted within the following two years;
3. Estimated application filing dates for all CAISO-approved transmission plan projects; and
4. A summary of any projects that have been reprioritized since the last quarterly briefing.

SECTION VI. UTILITY REPORT OF INFORMATION REGARDING FINANCING OF NEW ELECTRIC GENERATING AND TRANSMISSION CAPACITY

Every electric public utility shall biennially, on or before June 1 of every odd numbered year, furnish a report to the Commission of the financial information designated in Appendix A; provided, however, that no public utility shall be required to submit such financial information if such utility does not plan for a fifteen-year (15) period commencing with the year in which the financial information is to be filed to (1) construct within the State of California any new electric generating plant having in the aggregate a net capacity in excess of 50 MW, (2) modify, alter, or add to any existing electric generating plant that results in a 50 MW, or more, net increase in the electric generating capacity of an existing plant within the State of California, or (3) construct in California any electric transmission line facilities which are designed for immediate or eventual operation at any voltage in excess of 200 kV (except for the replacement or minor relocation of existing transmission line facilities, or the placing of additional conductors, insulators or their accessories on, or replacement of, supporting structures already built).

SECTION VII. ELECTRIC GENERATING AND RELATED TRANSMISSION FACILITIES SUBJECT TO THE WARREN-ALQUIST ENERGY RESOURCES CONSERVATION AND DEVELOPMENT ACT

If an electric public utility proposes to construct electric generating and related transmission facilities which are subject to the power plant siting jurisdiction of the CEC as set forth in Section 25500 et seq. of the Public Resources Code, it shall comply with the following procedure:

A. In accordance with Public Resources Code Section 25519(c), Public Utilities Code Section 1001, and CEQA, this Commission's Rules of Practice and Procedure 2.4 and 2.5 do not apply to any application filed pursuant to this section.

B. Upon acceptance of an electric utility's Notice of Intent (NOI) filing by the CEC, the utility shall provide an electronic copy of the NOI to the Executive Director of this Commission.

C. When an electric utility files with the CEC an application for certification (AFC) to construct an electric generating facility pursuant to Section 25519 of the Public Resources Code and any AFC regulations of the CEC, it shall provide an electronic copy of the AFC, including a copy of the CEC's Final Report in the NOI proceeding for the facility, to the Executive Director of this Commission.

D. No later than 30 days after acceptance for filing of the AFC referred to above in Subsection C, the utility shall file with this Commission an application for a CPCN. The application shall comply with this Commission's Rules of Practice and Procedure and shall include the data and information set forth in Appendix B hereto. In complying with this provision, the utility may include portions of the CEC's Final Report in its NOI proceeding by attaching such portions as an appendix to its application filed with this Commission. The utility may also include portions of the AFC filed with the CEC by reference. A copy of the application shall be provided to the CEC and to every person, corporation, organization, or public agency that has intervened in the CEC's AFC proceeding.

E. No later than 30 days after the filing of the application, the Commission staff shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application. The utility shall correct any deficiencies within 60 days thereafter, or explain in writing to the Commission staff why it is unable to do so. It shall include in any such letter an estimate of when it will be able to correct the deficiencies. Upon correction of any deficiencies in the application, any public hearings which are necessary may be held on the application while the utility's AFC application is under process before the CEC. The Commission may issue an interim decision on the application before the issuance by the CEC of a final decision in the AFC proceeding. However, any such interim decision shall not be final and shall be subject to review after the CEC issues its final decision in the AFC proceeding as prescribed in Public Resources Code Sections 25522 and 25530.

F. No later than 30 days after issuance of a certificate by the CEC in a final decision in the utility's AFC proceeding in accordance with Public Resources Code Sections 25209, 25522, and 25530 the Commission shall issue a decision on the application for a CPCN from this Commission, unless a later date for issuance of the decision is mutually agreed to by the Commission and the applicant, or is necessitated by conditions under Paragraph G.

G. If the CEC's certificate in the AFC proceedings sets forth requirements or conditions for the construction of the proposed electric generating facility which were not adequately considered in the proceeding before the Commission, and which will have a significant impact on the economic and financial feasibility of the project, or the rates of the utility, or on utility system reliability, the utility, or Commission staff, or any party, may request that the Commission hold a public hearing on such implications. Any such hearing, if granted, shall be initiated no later than 30 days after the filing of any such request. It is the intent of this Commission that a final decision shall be issued within 90 days after conclusion of the hearing, if held.

H. If judicial review of the CEC's issuance of a certificate in the AFC proceeding is sought in any court, the utility shall immediately notify this Commission and include a copy of the court filing.

SECTION VIII. ELECTRIC GENERATING FACILITIES NOT SUBJECT TO THE WARREN-ALQUIST ENERGY RESOURCES CONSERVATION AND DEVELOPMENT ACT

An electric public utility proposing to construct in this state new generation facilities in excess of 50 MW net capacity available at the busbar and related transmission facilities, or proposing to modify an existing generation facility and related transmission facilities in this state in order to increase the total generating capacity of the generation facility by 50 MW or more net capacity available at the busbar, shall file for a CPCN not less than 12 months prior to the date of a required decision by the Commission unless the Commission authorizes a shorter period for exceptional circumstances.

A. An application for a CPCN shall comply with this Commission's Rules of Practice and Procedure. In addition, it shall include or have attached to it the following:

1. The information and data set forth in Appendix B.
2. A statement of the reasons why and facts showing that the completion and operation of the proposed facility is necessary to promote the safety, health, comfort, and convenience of the public.
3. Safety and reliability information, including planned provisions for emergency operations and shutdowns.
4. A schedule showing the program for design, material acquisition, construction, and testing and operating dates.
5. Available site information, including maps and description, present, proposed, and ultimate development; and, as appropriate, geological, aesthetic, ecological, tsunami, seismic, water supply, population, and load center data, locations and comparative availability of alternate sites, and justification for adoption of the site selected.
6. Design information, including description of facilities, plan efficiencies, electrical connections to system, and description of control systems, including air quality control systems.
7. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.
8. Demonstration of compliance with other applicable

Commission policies (e.g., the Environmental and Social Justice [ESJ] Action Plan).

9. A Proponent's Environment Assessment (PEA) on the environmental impact of the proposed facility and its operation so as to permit compliance with the requirements of CEQA and this Commission's Rules of Practice and Procedure 2.4 and 2.5. If a PEA is filed, it may include the data described in Items 1 through 8, above.

B. An applicant may prepare and submit a draft version of an initial study or EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project if the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing, and provides the draft documents to Energy Division staff for review during the pre-filing period.

1. An applicant-prepared version of a draft CEQA document shall comply with the CEQA Guidelines, shall provide substantial evidence for all findings and conclusions, and shall include issue-specific technical studies (e.g., biological resource studies, cultural resource studies).
2. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis. Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

C. No later than 30 days after the filing of the CPCN application, the Commission staff shall review it and notify the utility of any deficiencies in the information and data submitted in the application.

D. The utility shall correct any deficiencies within 60 days after notice or explain in writing to the Commission staff why it is unable to do so. The utility shall include in any such letter an estimate of when it will be able to correct the deficiencies.

E. Upon correction of any deficiencies in the application, Commission staff shall determine whether CEQA applies, and if so, whether an EIR, MND, or ND has been or will be prepared. The process required by CEQA and Commission Rules 2.4 and 2.5 will be followed in addition to the Commission's standard decision-making process for applications. The Commission shall issue a decision within the time limits prescribed by Government Code Section 65920 et seq. (the Permit Streamlining

Act).

SECTION IX. TRANSMISSION LINE, POWER LINE, AND SUBSTATION FACILITIES

A. Transmission Line Facilities of 200 kV and Over

1. An electric public utility desiring to build transmission line facilities in this state for immediate or eventual operation at or above 200 kV that require a CPCN under Section III.A, above, shall:

   a. File an application for a CPCN not less than 12 months prior to the date of a required decision by the Commission unless the Commission authorizes a shorter period because of exceptional circumstances;
   b. Provide written notice to Energy Division staff not less than 12 months prior to the filing of a CPCN application; and
   c. Initiate pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than six (6) months prior to the filing of a CPCN application unless Energy Division staff authorize a shorter period in writing.

2. An application for a CPCN shall comply with this Commission's Rules of Practice and Procedure and shall also include the following:

   a. A detailed description of the proposed transmission facilities, including the proposed transmission line route and alternative routes, if any; proposed transmission equipment; such as tower design and appearance, heights, conductor sizes, voltages, capacities, substations, switchyards, etc.; and a proposed schedule for certification, construction, and commencement of operation of the facilities.
   b. A map of suitable scale of the proposed routing showing details of the right-of-way in the vicinity of settled areas, parks, recreational areas, scenic areas, and existing electrical transmission lines within one mile of the proposed route.
   c. A statement of facts and reasons why the public convenience and necessity require the construction and operation of the proposed transmission facilities.
   d. A detailed statement of the estimated cost of the proposed

facilities.

e. Reasons for adoption of the route selected, including comparison with alternative routes, including the advantages and disadvantages of each.

f. A schedule showing the program of right-of-way acquisition and construction.

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

h. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

i. Demonstration of compliance with other applicable Commission policies (e.g., the ESJ Action Plan).

j. A PEA or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and this Commission's Rules of Practice and Procedure, Rules 2.4 and 2.5. If a PEA is filed, it may include the data described in Items a through i above. An applicant may file a draft version of an initial study or EIR instead of a PEA in compliance with the requirements in IX.C below.

3. No later than 30 days after the filing of the application, the Commission staff shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application.

4. The utility shall correct any deficiencies within 60 days after notice or explain in writing to the Commission staff why it is unable to do so. The utility shall include in any such letter an estimate of when it will be able to correct the deficiencies.

5. Upon correction of any deficiencies in the application, the Commission staff shall determine whether CEQA applies, and if so, whether an EIR, MND, or ND has been or will be prepared. The process required by CEQA and Commission Rules of Practice and Procedure 2.4 and 2.5 will be followed in addition to

the Commission's standard decision-making process for applications. The Commission shall issue a decision within the time limits prescribed by Government Code Sections 65920 et seq. (the Permit Streamlining Act).

B. Transmission Line, Power Line, and Substation Facilities Designed to Operate Over 50 kV Which Are Not Included in Subsection A of this Section

1. Unless already included in an application before this Commission for a CPCN, an electric public utility desiring to build transmission line, power line, or substation facilities in this state for immediate or eventual operation over 50 kV, that require a PTC under Section III.B, above, shall:

   a. File an application for a PTC application not less than nine (9) months prior to the date of a required decision by the Commission;
   b. Provide written notice to Energy Division staff not less than 12 months prior to the filing of a PTC application; and
   c. Initiate pre-filing consultation with Energy Division staff pursuant to Section IX.B.1 not less than six (6) months prior to the filing of a PTC application unless Energy Division staff authorize a shorter period in writing.

2. A PTC application shall comply with the Commission's Rules of Practice and Procedure, including Rules 2.4 and 2.5, and shall include the following:

   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.
   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.
   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.

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

e. Any measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields (EMFs) generated by the proposed facilities.

f. Demonstration of compliance with other applicable Commission policies (e.g., the ESJ Action Plan).

g. A PEA or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and this Commission's Rules of Practice and Procedure 2.4 and 2.5. If a PEA is filed, it may include the data described in Items a through f above. An applicant may file a draft version of an initial study or EIR instead of a PEA in compliance with the requirements in IX.C below.

3. An application for a PTC need not include 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.

4. No later than 30 days after the filing of the application for a PTC, the Energy Division shall review it and notify the utility in writing of any deficiencies in the information and data submitted in the application.

5. Within 30 days of notice of such notice, the utility shall correct any deficiencies or explain in writing to the Energy Division when it will be able to correct the deficiencies or why it is unable to do so.

6. Upon correction of any deficiencies in the application, the Energy Division shall determine whether CEQA applies, and if so, whether an EIR, MND, or ND must be prepared, and the process required by CEQA and the Commission's Rules of Practice and Procedure 2.4 and 2.5 will be followed.

7. If the Commission finds that a project properly qualifies for an exemption from CEQA, the Commission will grant the PTC.

8. If the Energy Division determines, after the completion of an initial study, that the project would not have a significant adverse impact on the environment, the Energy Division will prepare an ND. If the initial study identifies potential significant effects, but the utility revises its proposal to avoid those effects, then the Commission could adopt an MND.

9. If the initial study identifies potentially significant environmental effects, the Energy Division will prepare an EIR. The severity and nature of the effects, the feasibility of mitigation, the existence and feasibility of alternatives to the project, and the benefits of the project would all be considered by the Commission in deciding whether to grant or deny the PTC.

C. Preparation of CEQA Documents and Commission Decision

1. An applicant may elect to prepare and submit a draft version of an initial study or a draft version of an EIR with its application in lieu of a PEA to support the CPUC in its preparation of a CEQA document for a project provided that the applicant first initiates pre-filing consultation with Energy Division staff pursuant to Rule 2.4 of the Commission's Rules of Practice and Procedure not less than 12 months prior to the filing of the application, unless Energy Division staff authorize a shorter period in writing, and provides the draft documents to Energy Division staff for review during the pre-filing period.

    a. An applicant-prepared version of a draft CEQA document shall comply with the CEQA Guidelines, shall provide substantial evidence for all findings and conclusions, and shall include issue-specific technical studies (e.g., biological resource studies, cultural resource studies).
    b. In accordance with Section 15084 of the CEQA Guidelines, the Commission shall subject all materials prepared by others to independent review and analysis. Any CEQA document sent out for public review shall reflect the independent judgment of the Commission.

2. Where the electric project proposed in a CPCN or PTC application has been evaluated and approved by the California Independent System Operator (CAISO) in a transmission plan prepared in accordance with the CAISO tariff approved by the

Federal Energy Regulatory Commission (FERC):

a. The statement of objectives required by 14 Cal. Code Regs. § 15124(b) in a CEQA document for the proposed project should consider the underlying purpose and project benefits of the proposed project as stated in the relevant CAISO transmission plan.

b. In a proceeding evaluating the issuance of a CPCN for a proposed transmission project, if all the provisions of Section IX.C.2 are satisfied, the Commission shall establish a rebuttable presumption in favor of a CAISO governing board-approved finding that such project is needed.

3. Section IX.C.2.b shall apply only to proceedings where:

a. The CAISO governing board has made explicit findings regarding the need for the proposed transmission project and has determined that the proposed project is the most cost-effective transmission solution.

b. The CAISO is a party to the proceeding.

c. The CAISO governing board-approved need evaluation is submitted to the Commission within sufficient time to be included within the scope of the proceeding.

d. There has been no substantial change to the scope, estimated cost, or timeline of the proposed transmission project as approved by the CAISO governing board.

SECTION X. NOTICE

A. Applications for a CPCN or PTC

Notice of the filing of each application for a CPCN required by Section III.A of this General Order and of the filing of each application for a PTC required by Section III.B of this General Order, shall be given by the electric public utility within ten days of filing the application:

1. By direct mail to:

a. The planning commission and the legislative body for each county or city in which the proposed facility would be located, the CEC, 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 Health Care Services, the State Water

Resources Control Board, the Air Resources Board, and other interested parties having requested such notification.

b. The following agencies and subdivisions in whose jurisdiction the proposed facility would be located: the Air Pollution Control District, the California Regional Water Quality Control Board, the California Coastal Commission, the State Department of Transportation's District Office, and any other State or Federal agency which would have jurisdiction over the proposed construction; and

c. All owners of land on which the proposed facility would be located and owners of property within 300 feet of the right-of-way as determined by the most recent local assessor's parcel roll available to the utility at the time notice is sent; and

2. By advertisement, not less than once a week, two weeks successively, in a newspaper or newspapers of general circulation that serves the county or counties in which the proposed facilities will be located, the first publication to be not later than ten days after filing of the application; and

3. By posting a notice on-site and off-site where the project would be located.

A copy of the notice shall be provided to the Commission's Public Advisor and the Energy Division on the same day it is mailed. A declaration of mailing and posting as required by this subsection shall be filed with the Commission within five (5) days of completion.

A copy of each application for electric generation facilities shall be served on the Executive Director of the Energy Commission. If applicable, a copy shall be served on the Executive Director of the Coastal Commission. If applicable, a copy shall be served on the Executive Director of the S.F. Bay Conservation and Development Commission. Upon request by any public agency, the applicant shall provide a copy of its application to said public agency. A copy of the application shall be posted on the utility's website.

B. Transmission Line, Power Line, and Substation Facilities Designed to Operate Over 50 kV Which Are Not Included in Subsection A of this Section

The utility shall give notice of the construction of any transmission line, power line, or substation facilities designed to operate over 50kV deemed exempt pursuant to Section III.B.1 herein, not less than 30 days before the date when construction is intended to begin by:

1. Direct mail to the planning director for each county or city in which the proposed facility would be located and the Executive Director of the Energy Commission; and
2. Advertisement, not less than once a week, two weeks successively, in a newspaper or newspapers of general circulation that serves the county or counties in which the proposed facility would be located, the first publication to be not later than 45 days before the date when construction is intended to begin; and
3. By posting a notice on-site and off-site where the project would be located.
4. Filing an advice letter with the Energy Division in accordance with General Order 96-B, which includes a copy and distribution list of the notices required by items 1-3 herein. On the same day, a copy of the advice letter must be delivered to the Commission's Public Advisor.

C. Contents of Notices

Each utility shall consult with the Energy Division and Commission's Public Advisor to develop and approve a standard for the notice required by subsections A and B, which shall contain, at a minimum, the following information:

1. The Application Number assigned by the Commission or the Advice Letter Number assigned by the utility; and
2. A concise description of the proposed construction and facilities, its purpose and its location in terms clearly understandable to the average reader; and
3. A summary of the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields generated by the proposed facilities, in compliance with Commission order; and
4. Instructions on obtaining or reviewing a copy of the application, including the Proponent's Environmental Assessment or available equivalent, from the utility; and
5. The applicable procedure for protesting the application or advice letter, as defined in Sections XI and XII, including the grounds for protest, when the protest period expires, delivery addresses for the Commission's Docket Office, Energy Division, and the applicant and how to contact the Commission's Public Advisor for assistance in filing a protest.

SECTION XI. PROTEST AND REQUEST FOR PUBLIC HEARINGS

Pursuant to the Commission's Rules of Practice and Procedure, Rule 2.6, those to whom notice has been sent under Section X.A and any other person entitled under the Commission's Rules of Practice and Procedure to participate in a proceeding for a CPCN or a PTC may, within 30 days after the notice was mailed or published, object to the granting in whole or in part of the authority sought by the utility and request that the Commission hold hearings on the application. Any such protest shall be filed in accordance with Rule 2.6. If the Commission, as a result of its preliminary investigation after such requests, determines that public hearings should be held, notice shall be sent to each person who is entitled to notice or who has requested a hearing.

The Commission's Public Advisor shall provide information to assist the public in submitting such protests.

SECTION XII. PROTEST TO REQUIRE THE UTILITY TO FILE FOR PTC

Those to whom notice has been given under Section X.B and any other person or entity entitled to participate in a proceeding for a PTC may, within 20 days after the notice was mailed and published, contest any intended construction for which exemption is claimed by the utility from the requirements of Section III.B if such persons or entities have valid reason to believe that any of the conditions described in Section III.B.2 exist or the utility has incorrectly applied an exemption as defined in Section III. The protest shall be filed with the Energy Division, specifying the relevant utility advice letter number, in accordance with General Order 96-B, Sections 3.11, 7.4.1, and 7.4.2. On the same date a protest is filed with the Commission, the protestant shall serve a copy on the subject utility by mail. The utility shall respond within five business days of receipt and serve copies of its response on each protestant and the Energy Division. Construction shall not commence until the Executive Director has disposed of the protest .

Within 30 days after the utility has submitted its response, the Executive Director, after consulting with the Energy Division, shall issue a disposition letter on whether: the utility is to file an application for a PTC, or the protest is dismissed for failure to state a valid reason. Also, the Executive Director shall state the reasons for granting or denying the protest and provide a copy of the disposition letter to the Commission's Public Advisor.

The utility, any persons that filed a protest to the advice letter, or other persons or entities (to the extent authorized by General Order 96-B or its successor regulation) may request Commission review of the Executive Director's or Energy Division's disposition of an advice letter, pursuant to General Order 96-B, General Rule 7.6.3 (or a successor regulation).

The Commission's Public Advisor shall provide information to assist the public in submitting such protests.

SECTION XIII. COMPLAINTS AND PREEMPTION OF LOCAL AUTHORITY

A. Complaints may be filed with the Commission for resolution of any alleged violations of this General Order pursuant to Article 4 of the Commission's Rules of Practice and Procedure. A complaint which does not allege that the matter has first been brought to the staff for informal resolution may be referred to the staff to attempt to resolve the matter informally (Rule of Practice and Procedure 4.2(b)).

B. This General Order clarifies that local jurisdictions acting pursuant to local authority are preempted from regulating electric power line projects, distribution lines, substations, or electric facilities constructed by public utilities subject to the Commission's jurisdiction. However, in locating such projects, the public utilities shall consult with local agencies regarding land use matters. In instances where the public utilities and local agencies are unable to resolve their differences, the Commission shall set a hearing no later than 30 days after the utility or local agency has notified the Commission of the inability to reach agreement on land use matters.

C. Public agencies and other interested parties may contest the construction of under-50-kV distribution lines and electric facilities by filing a complaint with the Commission pursuant to Article 4 of the Commission's Rules of Practice and Procedure.

SECTION XIV. STATE AGENCY REVIEW OF ELECTRIC GENERATING AND RELATED TRANSMISSION FACILITIES NOT SUBJECT TO THE WARREN-ALQUIST ENERGY RESOURCES CONSERVATION AND DEVELOPMENT ACT

Nothing in this order shall be construed to preempt or otherwise limit the jurisdiction of state agencies other than this Commission to exercise the full range of their jurisdiction under state or federal law over facilities subject to this order.

A coastal development permit shall be obtained from the Coastal Commission for development of facilities subject to this order in the coastal zone.

SECTION XV. CEQA COMPLIANCE

Construction of facilities for which a CPCN or PTC is required pursuant to this General Order shall not commence without either a finding that it can be seen with certainty that there is no possibility that the construction of those facilities may have a significant effect on the environment or that the project is otherwise exempt from CEQA, or the adoption of a final EIR, MND, or ND. Where authority must be granted for a project by this Commission, applicants shall comply with Rules 2.4 and 2.5 of the Commission's Rules of Practice and Procedure. This latter requirement does not apply to applications covering generating and related transmission facilities for which a certificate authorizing construction of the facilities has been or will also be issued by the CEC. For all issues relating to the siting, design, and construction of electric generating plant or transmission lines as defined in Sections VIII and IX.A herein or electric power lines or substations as defined in Section IX.B herein, the Commission will be the Lead Agency under CEQA, unless a different designation has been negotiated between the Commission and another state agency consistent with CEQA Guidelines § 1505l(d).

Pursuant to Sections 15107 and 15110 of the CEQA Guidelines, the Commission strives to complete Proposed Final MNDs or NDs for projects without federal agency involvement within 270 days or sooner from the date the PTC or CPCN application is deemed complete. Pursuant to Sections 15108 and 15110 of the CEQA Guidelines, the CPUC would strive to complete Proposed EIRs for projects without federal agency involvement within 455 days or sooner from the date that the application is deemed complete. Sections 15109 and 15110 of the CEQA Guidelines shall apply regarding the suspension of time periods and projects with federal involvement.

Projects requiring CPUC approval of a PTC that qualify for an MND or ND and have no federal agency involvement could involve completion of CEQA review within 270 days. In accordance with Section 15070 of the CEQA Guidelines, CPUC shall prepare or have prepared a proposed ND or MND for a project when:

A. The initial study shows that there is no substantial evidence (as defined in Section 15384 of the CEQA Guidelines), in light of the whole record before the agency, that the project may have a significant effect on the environment, or

B. The initial study identifies potentially significant effects, but:

    1. Revisions in the project plans or proposals made by, or agreed to by the applicant before a proposed mitigated negative declaration and initial study are released for public review would avoid the effects or mitigate the effects to a point where clearly no significant effects would occur, and
    2. There is no substantial evidence, in light of the whole record before the agency, that the project as revised may have a significant effect on the environment.

Appendix A - General Order No. 131-D

INFORMATION TO BE INCLUDED IN THE UTILITY REPORT
REGARDING FINANCING OF NEW ELECTRIC
GENERATING CAPACITY, TRANSMISSION LINE, AND POWER
LINE PROJECTS

I. A statement, detailing the economic assumptions used to project all construction expenditures and annual operating costs, including the methodology, assumptions, and sources and authorities associated therewith for a fifteen-year (15) period commencing with the year in which the report is filed, for each of the following:

A. Operating Revenues
   1. Electric
   2. Gas, if applicable
   3. Miscellaneous
   4. Total

B. Capital Costs to be Added to Rate Base
   1. Direct Material Costs
   2. Direct Labor Costs
   3. Allowance for Funds Used During Construction (AFUDC)
   4. Construction Work in Progress (CWIP) added to rate base due to incentive
   5. Overhead
   6. Others

C. Long-Term Capital Costs
   1. Rate of Return
      - Return on Equity (ROE) (common stock)
      - Return on Preferred Stock
      - Long-Term Debt
   2. Depreciation
   3. Taxes on ROE

D. Operating and Maintenance (O&M) and Administrative and General (A&G) Expenses and Taxes
   1. Cost of Electric Energy
   2. Cost of Gas sold, if applicable
   3. Transmission and Distribution
   4. Maintenance
   5. Insurance
   6. Taxes on Income
   7. Property and Other Taxes

8. Other
9. Total

E. Operating Income

F. Other Income and Deductions
1. Gains on Bonds Purchased for Sinking Fund
2. Subsidiary Income
3. Other – Net
4. Total

G. Income Before Interest Charges

H. Interest Charges
1. Short-term
2. Long-term
3. Less Allowance for Borrowed Funds Used During Construction
4. Total

I. Net Income

J. Preferred Dividend Requirement

K. Earnings Available for Common Stock

L. Average Number of Shares of Common Stock Outstanding (Thousands)

M. Earnings Per Share of Common Stock

N. Dividends Per Share of Common Stock
1. Declared Basis
2. Paid Basis

II. An estimate for each of the following capital requirements items for each year for a fifteen-year period commencing with the year in which the report is filed:

A. Construction expenditures by year, including materials, labor, overhead, and AFUDC, broken down by:
1. Generation projects over $100 million, including those, if any, located out-of-state

a. Busbar, including switchyard, expenditures

2. All other generation projects, including those, if any, located out-of-state

a. Busbar, including switchyard, expenditures
b. Associated transmission expenditures

3. Non-generation transmission expenditures
4. Distribution expenditures
5. Other expenditures

Breakdown of each item in 1 above into the following elements:

Directs	(M&S + Labor)	Indirects	AFDC	Total
	$	$	$	$

B. Bond retirements, sinking fund retirements, etc.

C. Investments in subsidiary companies

III. An estimate for each of the following items for each year for a fifteen-year period commencing with the year in which the report is filed:

A. Capital balances as of January 1

B. Capital ratios as of January 1

C. Imbedded costs of debt and preferred stock

D. Debt, preferred and common stock issues:
1. Amount ($ and shares)
2. Yield and cost of each issue

E. Income tax information
1. Tax operating expense
2. State tax depreciation
3. Federal tax depreciation
4. ITC or other credits available and used

F. Short-term debt balances

G. Annual equivalent rate used to compute the Allowance for Funds Used During Construction

IV. Data showing the estimated Results of Operation for electric utility operations for each year for a fifteen-year (15) period, commencing with the year in which the report is filed, in the format set forth below:

A. Kilowatt-hour Sales
1. Total
2. Residential

B. Average Price (¢/kWh)

C. Number of Residential Customers

D. Gross Revenue – Total
   1. Base Rates
   2. ECAC Rates
   3. ECAC Rate Increases
   4. Non-ECAC Rate Increases
   5. Misc. Operating Revenues

E. Operating Expenses – Total
   1. Production – Fuel and Purchased Power – Total
      a. Oil
      b. Gas
      c. Nuclear
      d. Coal
      e. Geothermal
      f. Combined Cycle
      g. Purchased Power
      h. Other (explain)

   2. Production O&M (non-fuel)
   3. Transmission
   4. Distribution
   5. Customer Accounts
   6. A&G
   7. Depreciation & Amortization
   8. Taxes – Total
      a. State Income
      b. Federal Income
      c. Ad Valorem
      d. Other

   9. Other (explain)

F. Net Operating Income

G. Rate Base (Weighted Average)

H. Rate of Return

I. Net-to-Gross Multiplier

V. For those electric utilities which also operate other public utility departments, such as natural gas, steam, and water service, an estimate of the following financial information by department for each year for a fifteen-year (15) period, commencing with the year in which the report is filed. Any separate utility operation that contributes to less than one (1) percent of the utility's total gross operating revenues may be excluded.

A. Gross Revenue
B. Operating Expenses
C. Net Operating Income
D. Rate Base (Weighted Average)
E. Rate of Return

VI. The following variables will be provided by the staff of the Public Utilities Commission for use by the utility in generating certain financial information required by Appendix A:

A. Return on Common Equity
B. Dividend Yield
C. Market to Book Ratio
D. Cost of Long-Term Debt (including incremental cost)
E. Cost of Preferred Stock (including incremental cost)
F. Common Stock Price
G. Annual equivalent rate used to compute the Allowance for Funds Used During Construction

These variables will be furnished 60 days before the annual utility report is due and will be developed by the staff based on its independent expertise.

Appendix B – General Order No. 131-D

INFORMATION TO BE INCLUDED IN AN APPLICATION
FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND
NECESSITY FOR ELECTRIC GENERATING FACILITIES

I. A detailed description of the proposed generating facility and related facilities and the manner in which the same will be constructed, including the type, size, fuel capabilities, and capacity of the generating facilities.

II. A map of suitable scale showing the location of the proposed power plant and related facilities, and a description of the location of the proposed power plant and related facilities.

III. A listing of federal, state, regional, county, district, or municipal agencies from which approvals either have been obtained or will be required covering various aspects of the proposed facility, including any franchises and health and safety permits and the planned schedule for obtaining those approvals not yet received.

IV. Load and resource data setting forth recorded and estimated loads (energy and demands), available capacity and energy, and margins for 5 years actual and 20 years estimated on the same basis, as reported to the CEC including a statement of the compatibility of the proposed generating facility with the most recent biennial report issued by the CEC pursuant to Section 25309 of the Public Resources Code.

V. Existing rated and effective operating capacity of generating plants and the planned additions for a ten-year (10) period.

VI. Estimated cost information, including plant costs by accounts, all expenses by categories, including fuel costs, plant service life, capacity factor, total generating cost per kWh (1) at plant, and (2) including related transmission, levelized for the economic life of the plant, year by year for the 12 years commencing with the date of commercial operation of the plant, and comparative costs of other alternatives considered on a levelized or year-by-year basis depending upon availability of data. Estimated capital and operating costs of power to be generated by the proposed plant for all competitive fuels which may be lawfully used in the proposed plant. When substantially the same data are prepared for utility planning purposes they may be used to satisfy all or any portion of these requirements.

VII. For any nuclear plant a statement indicating that the requisite safety and other license approvals have been obtained or will be applied for.

VIII. Such additional information and data as may be necessary for a full understanding and evaluation of the proposal.

(End of Appendix)

Appendix C

Selected Party Responses to R.23-05-018 Data Request 01

From:	Alexander, Tommy
To:	Martelino, Trixie; CxGr@pge.com; LJT7@pge.com; BNE7@pge.com; D7BD@pge.com; DTK5@pge.com; Grady.Mathai-Jackson@pge.com; JLLm@pge.com; Mia.berrios@pge.com; oxv5@pge.com; Yvonne.Yang@pge.com; Lori.Charpentier@sce.com; jon.parker@sce.com; Delon.Richardson@sce.com; Gary.Chen@sce.com; amckean@socalgas.com; david.leblond@sce.com; JLSalazar@SoCalGas.com; Robert.Pontelle@sce.com; KBourbois@sdge.com; CSTaylor@sdge.com; CFaber@SempraUtilities.com; EMartin8@sdge.com; SSidhar1@SempraUtilities.com; SWoldegiorgis@sdge.com; TMKirch2@sdge.com; WWaideli@sdge.com; LCottle@SheppardMullin.com; JHolland@gridliance.com; ctomchuk@vea.coop; RKMoore@GSwater.com; AAmirali@Starwood.com; Dan.Marsh@LibertyUtilities.com; djoseph@lspower.com; MMilburn@LSPower.com; Andy.Flajole@nexteraenergy.com; Tracy.C.Davis@nee.com; CaliforniaDockets@PacifiCorp.com; cathie.allen@pacificorp.com; JGibson@DowneyBrand.com
Cc:	Peterson, Robert; Henriquez, Roxanne; Sison-Lebrilla, Elaine; Mulligan, Jack M.; Wright, Tharon; Forsythe, John
Subject:	RE: R.23-05-018 Data Request 01 - GO 131 Update Proceeding
Date:	Friday, February 16, 2024 4:28:00 PM

Hello all,

SCE and PG&E have requested that the deadline to respond to R.23-05-018 Data Request 01 be extended by one week from February 29 to March 8, 2024. This email hereby grants that request and expands the time extension to all respondents.

Please submit your responses to R.23-05-018 Data Request 01 by **Friday, March 8, 2024**.

Best,

Tommy Alexander (He/Him)**,** Project Manager
California Public Utilities Commission
tommy.alexander@cpuc.ca.gov | 213-266-4748

From: Alexander, Tommy
Sent: Monday, January 29, 2024 5:54 PM
To: Martelino, Trixie <MTMU@pge.com>; CxGr@pge.com; LJT7@pge.com; BNE7@pge.com; D7BD@pge.com; DTK5@pge.com; Grady.Mathai-Jackson@pge.com; JLLm@pge.com; Mia.berrios@pge.com; oxv5@pge.com; Yvonne.Yang@pge.com; Lori.Charpentier@sce.com; jon.parker@sce.com; Delon.Richardson@sce.com; Gary.Chen@sce.com; amckean@socalgas.com; david.leblond@sce.com; JLSalazar@SoCalGas.com; Robert.Pontelle@sce.com; KBourbois@sdge.com; CSTaylor@sdge.com; CFaber@SempraUtilities.com; EMartin8@sdge.com; SSidhar1@SempraUtilities.com; SWoldegiorgis@sdge.com; TMKirch2@sdge.com; WWaideli@sdge.com; LCottle@SheppardMullin.com; JHolland@gridliance.com; ctomchuk@vea.coop; RKMoore@GSwater.com; AAmirali@Starwood.com; Dan.Marsh@LibertyUtilities.com; djoseph@lspower.com; MMilburn@LSPower.com; Andy.Flajole@nexteraenergy.com; Tracy.C.Davis@nee.com; CaliforniaDockets@PacifiCorp.com; cathie.allen@pacificorp.com; JGibson@DowneyBrand.com
Cc: Peterson, Robert <Robert.Peterson@cpuc.ca.gov>; Henriquez, Roxanne <Roxanne.Henriquez@cpuc.ca.gov>; Sison-Lebrilla, Elaine <Elaine.Sison-Lebrilla@cpuc.ca.gov>; Mulligan, Jack M. <jack.mulligan@cpuc.ca.gov>; Wright, Tharon <Tharon.Wright@cpuc.ca.gov>
Subject: R.23-05-018 Data Request 01 - GO 131 Update Proceeding

Hello all:

We are submitting this data request (R.23-05-018 Data Request 01) to support the development of a Staff Proposal in Phase 2 of the General Order (GO) 131-D update proceeding (R.23-05-018).

This data request is being submitted to all parties in the R.23-05-018 proceeding that fall into any of the following categories: investor-owned utilities (IOUs), non-IOU participating transmission owners (PTOs), or other transmission developers and electric utilities. One question, Question 11, is intended only for non-IOU PTOs and independent transmission developers. All other questions in this data request are intended for all recipients. Please be aware that any responses to these questions may be appended to the Phase 2 Staff Proposal and thereby made public in the proceeding record.

Please provide explanations to support your responses to any questions inviting yes/no answers. Feel free to provide charts or diagrams where applicable, and please be sure to specify if any charts or diagrams are being used to address multiple questions.

Please respond **within 30 calendar days** and no later than February 29, 2024. Let us know if you have questions.

R.23-05-018 Data Request 01:

-

1. Please answer the following questions regarding the internal utility planning, design, and application process for electrical transmission projects:
   a. On average, how long does it take for a project to be submitted to the CPUC via CPCN or PTC application after it has been approved in a CAISO Transmission Plan? Provide the data used to calculate the average.
   b. Please explain in detail the key time components in your company's internal planning and application process for electric transmission projects. Provide at least three relevant examples from the last ten years that illustrate a representative range of cases (i.e., the middle and tail ends of the range used to calculate the requested average). For each example, discuss the factors that contributed to the duration of each component of the internal planning and application process.
   c. At what percentage of design completeness (e.g., 30% design, 60% design) does your company typically aim to file an application with the CPUC?
   d. At what point in the project planning and design process does your company engage contractors to support scoping, routing, and preparation of technical studies?
   e. Please describe any ideas that could accelerate the internal utility planning and application process prior to the submittal of an application to the CPUC.

2. Please answer the following questions regarding application filing and pre-filing review:
   a. Once a project is approved by CAISO, should the CPUC require the project proponent to file an application within a specified time window after CAISO approval (e.g., within one year) or within a specified time window prior to the required or forecasted in-service date (e.g., two years prior to the in-service date)? Alternatively, is it feasible to institute different filing deadlines based on project type and complexity? Please explain.
   b. Are there modifications to the pre-filing review process or application process that would incentivize applicants to initiate pre-filing consultation with the CPUC earlier in the project design process? Please explain.
   c. Are there other modifications to GO 131-D that could enable applicants to provide project information (e.g., in-service date, project objective and design, potentially feasible siting/routing) to the CPUC on an expedited basis for CAISO-approved projects, or that could otherwise enable the CPUC to begin environmental review sooner? To what extent can this information be provided prior to application filing via the Transmission Project Review (TPR) Process or via existing recurring meetings between IOUs and CPUC staff? Please explain.

3. Please answer the following questions regarding the provision of cost estimates:
   a. Please explain in detail the point in your internal planning process at which cost estimates are typically submitted to the CPUC, when required. What actions are required for applicants to provide an estimated cost for PTC projects and a statement of why the project is needed? What challenges or barriers do applicants encounter during this process? Can they be addressed by the Commission, and if so, in what ways can they be addressed?
   b. Would showing that a project was selected as a result of a competitive process at the CAISO, which includes a cost cap, satisfy requirements to demonstrate the cost and need for CPCN and PTC projects?
   c. To what extent are any delays in the provision of cost estimates attributable to the design and planning of interconnection to the distribution system? Please explain and provide examples.
   d. Please also explain the typical time periods for cost estimates to reach different levels of reliability (e.g., 100% contingency, 50% contingency, 25% contingency), and what factors may impact these time periods.
   e. When and why do costs submitted to the CPUC in the application process differ from costs identified in the CAISO Transmission Plan? Please provide a range of examples of such projects and explain what

caused the difference.

4. Please answer the following questions regarding the CPCN and PTC exemption criteria:
    a. Would adding specificity to the CPCN and PTC exemption criteria (e.g., including a non-exhaustive list of examples of "equivalent facilities or structures", "minor relocation", and "accessories") increase applicant certainty regarding whether an exemption would apply and/or increase the number of projects for which an exemption may apply? If so, please provide specific suggestions (e.g., converting existing lattice towers or wood poles to steel monopoles no more than X percent taller than the existing structures). If additional terms are proposed, please provide definitions.
    b. Would adding specificity to the term "minor relocation of existing power line facilities" in Section III.A (for CPCN exemptions) increase advice letter filings and reduce application filings (e.g., by increasing the number of projects that are eligible for PTC exemptions 1b, 1c, and 1e)? Please explain.
    c. Would reformatting the CPCN exemptions in GO 131-D Section III.A as an ordered list, similar to the existing list of PTC exemptions in Section III.B.1, increase applicant certainty regarding whether an exemption would apply?
    d. Are there any other pros and cons to making such modifications? Please explain.

5. What are the current typical lead times for obtaining equipment critically necessary to complete transmission projects (such as transformers, circuit breakers, busbars, conductors, etc.)? What factors influence the calculation of estimated lead times? Are there any emerging issues (e.g., supply chain) that will significantly impact future lead times? What actions can transmission developers take to expedite timelines for obtaining equipment? Could explicit authorization to procure long-lead-time equipment expedite transmission projects?

6. Of all the transmission projects approved by CAISO in the past five years, is there a subset of projects that should be prioritized (e.g., policy-driven transmission projects) for California to reach its emission reduction goals? Please explain.
    a. Would prioritizing these projects help streamline permitting? If so, can this be accomplished by changes to GO 131-D in Phase 2 of this proceeding?
    b. To what extent could more detailed project routing and siting work coupled with feasibility studies and high-level environmental constraint analyses conducted up front during the CAISO transmission project

identification and planning processes streamline subsequent State siting approvals?

c. Are there other changes to the electric transmission planning and permitting process that would be necessary to achieve State emission reduction goals, e.g., new legislation or changes to GO 96-B? Please describe any recommended changes in detail.

d. More broadly, is there an optimal way to sequence the build-out of the grid? Are there workforce or supply chain constraints that prevent projects from being constructed simultaneously?

7. In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023, settling parties proposed adding "power line facilities or substations" to the second clause of section III.B.1.g. Of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, how many are located within a "utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies"? Please provide a list of these projects and the applicable utility corridor(s). Of these projects, how many currently qualify for exemption "g", and how many would qualify for exemption "g" if the settlement agreement suggestion were to be implemented? Do the parties anticipate other, future utility corridors that would impact the use of exemption "g"? Please explain.

8. Please explain whether the proposals in the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023 are consistent with the following provision of GO 131-D or whether this provision should be amended: "For all issues relating to the siting, design, and construction of electric generating plant or transmission lines as defined in Sections VIII and IX.A herein or electric power lines or substations as defined in Section IX.B herein, the Commission will be the Lead Agency under CEQA, unless a different designation has been negotiated between the Commission and another state agency consistent with CEQA Guidelines § 15051(d)."

9. How should the ability of non-wire alternatives and distributed energy resources to meet project objectives be evaluated? Should the CPUC still pursue the deferral of distribution upgrades through the use of distributed energy resources? What is CAISO's current process for reporting on the feasibility of non-wire transmission alternatives (and can this process be improved to provide the CPUC with information that better informs the CEQA process)? How are distribution-level non-wire alternatives considered by an applicant prior to application submittal? What opportunities could the CPUC pursue to streamline review of non-wire distribution-level alternatives, and should the CPUC pursue this issue?

10. Please review the generic list of permits required for a typical electric transmission project at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/g/5066-generictransmissionlinepermit.pdf. Should this list be updated? If so, please use the format in the linked table to list all the permits that are required for a typical transmission project (PTC and CPCN) from all federal and State agencies. If there are no "typical" projects, please use at least three projects as examples and list the permits required for each project.

For non-IOU PTOs and independent transmission developers:

11. Have any independent transmission developers experienced project delays due to actions of incumbent utilities that they were competing against in a CAISO competitive bidding process? Please explain the circumstances and any actions the CPUC could take to streamline utility processes relating to such delays.

Thank you,

Tommy Alexander (He/Him), Project Manager
California Public Utilities Commission
tommy.alexander@cpuc.ca.gov | 213-266-4748

Southern California Edison
R.23-05-018 – Amend GO 131-D

DATA REQUEST SET E D - S C E - 0 0 1

To: Energy Division
Prepared by: Sam Shammas
Job Title: Engineering Senior Manager
Received Date: 1/29/2024

Response Date: 3/8/2024

Question 01.c:
Please answer the following questions regarding the internal utility planning, design, and application process for electrical transmission projects:
At what percentage of design completeness (e.g., 30% design, 60% design) does your company typically aim to file an application with the CPUC?

Response to Question 01.c:
SCE typically files applications with the CPUC when project design completeness is approximately 30%.[1] This level of preliminary engineering and design typically provides sufficient detail to identify transmission facilities, structure types, structure locations, line routes, and pulling and stringing locations at a high level (desktop or field level). This level of design typically involves creating a Power Line Systems – Computer Aided Design and Drafting (PLS-CADD) model, initial AutoCAD drawings (plans and profiles), preliminary staking tables, initial access road and grading assessments, and preliminary geotechnical evaluations (typically desktop-level), among other activities. This level of detail provides adequate information for SCE to estimate anticipated environmental and ground disturbance impacts of the project.

[1] Although SCE typically files applications with the CPUC based upon 30% design, each project is unique, and depending upon circumstances, SCE may file an application with more or less design completed.

DATA REQUEST SET E D - S C E - 0 0 1

To: Energy Division
Prepared by: Lori Charpentier
Job Title: Senior Manager, Regulatory Affairs Infrastructure Licensing
Received Date: 1/29/2024

Response Date: 3/8/2024

Question 01.e:
Please answer the following questions regarding the internal utility planning, design, and application process for electrical transmission projects:
Please describe any ideas that could accelerate the internal utility planning and application process prior to the submittal of an application to the CPUC.

Response to Question 01.e:
SCE appreciates the opportunity to provide feedback on potential approaches to accelerate the application process. The internal utility planning process could be expedited through reducing the amount of information required to file an application. The Proponent's Environmental Assessment ("PEA") checklist and guidelines require utilities to prepare an extensive amount of information prior to filing an application, including detailed engineering.[1] For example, for a transmission line, the size, type, location, and height of structures are all required to be identified and mapped in GIS. For substations, not only is the substation location needed, but layout, location of equipment, and height of all structures are also required. Consequently, the larger and more complex the project, the more time is required to develop the engineering. Projects are often deemed incomplete if any component of the checklist is not fully addressed, therefore, preparing SCE's PEAs is a lengthy process given the need to include the required extensive and detailed information. Revising the PEA checklist to provide more approximations (*e.g*., range of pole heights and approximate structure locations) would enable utilities to file applications with the CPUC faster.

Additionally, and particularly if that level of detail is still required, SCE recommends referring to the Joint Motion for Adoption of Phase 1 Settlement Agreement ("Settlement Agreement") submitted in proceeding R.13-05-018 for proposals to expedite project development through completion, specifically the provision regarding submittal of an applicant-prepared CEQA document in lieu of a PEA.[2] As discussed in the Settlement Agreement, by allowing for applicant-prepared CEQA documents to take the place of a Proponent's Environmental Assessment ("PEA"), the time between project initiation and the Commission's issuance of a draft environmental document would be reduced substantially by eliminating the duplication of CEQA analysis

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[1] Commission's Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments includes 91 pages of detailed requirements for the PEA.
[2] Order Instituting Rulemaking to Update and Amend Commission General Order 131-D. (R. 23-05-018.) Joint Motion for Adoption of Phase 1 Settlement Agreement, jointly filed by San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company, representing 18 settling parties.

conducted by Commission consultants.[3]

[3] SCE provided a similar response to an Energy Division data request regarding opportunities to expedite the filing of CAISO Transmission Process Plan approved projects at the CPUC, Data Request ED-SCE-CAISO TPP to CPUC Filing Timeline-231020.

Southern California Edison
R.23-05-018 – Amend GO 131-D

DATA REQUEST SET E D - S C E - 0 0 1

To: Energy Division
Prepared by: Lori Charpentier
Job Title: Senior Manager, Regulatory Affairs Infrastructure Licensing
Received Date: 1/29/2024

Response Date: 3/8/2024

Question 02.a:
Please answer the following questions regarding application filing and pre-filing review:
Once a project is approved by CAISO, should the CPUC require the project proponent to file an application within a specified time window after CAISO approval (e.g., within one year) or within a specified time window prior to the required or forecasted in-service date (e.g., two years prior to the in-service date)? Alternatively, is it feasible to institute different filing deadlines based on project type and complexity? Please explain

Response to Question 02.a:
SCE strongly recommends against establishment of a designated timeframe for filing an application following CAISO approval, as thoroughly discussed in SCE's Reply Comments on the Ruling Inviting Comment on Phase 2 Issues[1] ("SCE's Reply Comments"). As discussed in SCE's Reply Comments, the rigorous project development process is not conducive to broad deadlines applied to all projects, irrespective of complexity, and especially with the substantial filing requirements for a Certificate of Public Convenience and Necessity or Permit to Construct. The Proponent's Environmental Assessment ("PEA") is a detailed document that requires completion of preliminary engineering and extensive impact analysis. Unless the level of detail required in the PEA is reduced, a short window from CAISO approval to CPUC application filing is not likely to be feasible in most instances.

SCE believes that even accelerated filing timelines would not address delays that are typically experienced during the environmental review and CPUC licensing (case-in-chief) process.

Requiring utilities to file within a specified timeframe does not account for factors outside the utilities' control, such as seasonal limitations on environmental surveys.

It is not clear whether it would be feasible to institute different filing deadlines based upon project type and complexity, as oftentimes complexity is not known until more detailed design and environmental analysis activites are completed. SCE would like to better understand such a proposal prior to commenting on its feasibility.

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[1] R. 23-05-018. Order Instituting Rulemaking to Update and Amend Commission General Order 131-D. SCE's Reply Comments on the Ruling Inviting Comment on Phase 2 Issues, pp. 25-28.

Southern California Edison
R.23-05-018 – Amend GO 131-D

DATA REQUEST SET E D - S C E - 0 0 1

To: Energy Division
Prepared by: Lori Charpentier
Job Title: Senior Manager, Regulatory Affairs Infrastructure Licensing
Received Date: 1/29/2024

Response Date: 3/8/2024

Question 07:
In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023, settling parties proposed adding "power line facilities or substations" to the second clause of section III.B.1.g. Of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, how many are located within a "utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies"? Please provide a list of these projects and the applicable utility corridor(s). Of these projects, how many currently qualify for exemption "g", and how many would qualify for exemption "g" if the settlement agreement suggestion were to be implemented? Do the parties anticipate other, future utility corridors that would impact the use of exemption "g"? Please explain.

Response to Question 07:
The Settlement Agreement proposes to add "power line facilities or substations" to the second clause of GO 131-D Section III.B.1.g to clarify the grammar.[1] This revision is not intended to change the intent of exemption "g" and simply brings clarity to the exemption.

None of SCE's projects included in the last five CAISO Transmission Plans (prior to 2022-2023) would have qualified as exempt under GO 131-D Section III.B.1.g.

[1] R. 23-05-018. Order Instituting Rulemaking to Update and Amend Commission General Order 131-D. Joint Motion for Adoption of Phase 1 Settlement Agreement.

PACIFIC GAS AND ELECTRIC COMPANY
GO 131-D Update and Amend OIR
Rulemaking 23-05-018
Data Response

PG&E Data Request No.:	ED_001-Q001		
PG&E File Name:	GO-131-D-UpdateandAmendOIR_DR_ED_001-Q001		
Request Date:	January 30, 2024	Requester DR No.:	001
Date Sent:	March 8, 2024	Requesting Party:	Energy Division
PG&E Witness:		Requester:	Tommy Alexander

SUBJECT: R.23-05-018 DATA REQUEST 01 - GO 131 UPDATE PROCEEDING

QUESTION 1.A

1. Please answer the following questions regarding the internal utility planning, design, and application process for electrical transmission projects:

a. On average, how long does it take for a project to be submitted to the CPUC via CPCN or PTC application after it has been approved in a CAISO Transmission Plan? Provide the data used to calculate the average.

ANSWER 1.A

a. The answer to Question 1.a can be derived from Attachment 1 to Pacific Gas & Electric Company's (PG&E's) Data Response dated January 17, 2024. According to this data, the average amount of time between Transmission Planning Process (TPP) approval year and application filing was approximately 6.4 years. Relevant data from Attachment 1 is provided in Table 1-a and includes those California Independent System Operator (CAISO)-approved projects (per the latest TPP) with filed permit applications. A significant portion of this timeline is attributed to preparation of the Permit to Construct (PTC) or Certificate of Public Convenience and Necessity (CPCN) application package. Please see Response 1.b for specific examples of how PTC or CPCN applications have taken significant amounts of time.

TABLE 1-a

Project Name	Transmission Plan Approved*	Permit Type	Filing Date	Approximate Time from TPP Approval to CPUC Filing (years)
Martin 230 kilovolt (kV) Bus Extension	2014-2015	CPCN	12/28/2017	2

TABLE 1-a				
Project Name	**Transmission Plan Approved***	**Permit Type**	**Filing Date**	**Approximate Time from TPP Approval to CPUC Filing (years)**
Lockeford-Lodi Area 230 kV Development	2012-2013	CPCN	Sep 2023	10
Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	2008	PTC	2/23/2017	9
Estrella Substation Project	2013-2014	PTC	Jan 2017	3
Ravenswood – Cooley Landing 115 kV Line Reconductor	2009**	PTC	12/23/2017	8
Vierra 115 kV Looping Project	2010-2011	PTC	Jun 2018	7
Plainfield Substation (CAISO name: Vaca Davis Voltage Conversion)	2017-2018 (rescoped)	PTC	Expected Q1 2024	6

*Approval year reflects latest TPP approval year, in cases where project was rescoped by CAISO.

**Denotes correction from previously provided data.

QUESTION 1.B

b. Please explain in detail the key time components in your company's internal planning and application process for electric transmission projects. Provide at least three relevant examples from the last ten years that illustrate a representative range of cases (i.e., the middle and tail ends of the range used to calculate the requested average). For each example, discuss the factors that contributed to the duration of each component of the internal planning and application process.

ANSWER 1.B

As indicated in PG&E's Data Response dated November 21, 2023, there are three main factors that affect the timeline to file an electric transmission project application pursuant to General Order (GO) 131-D. These factors are (1) PG&E's prioritization and reprioritization of projects, (2) the time it takes to execute projects, and (3) for projects that are approved through the CAISO TPP, putting a project on hold if CAISO pauses or rescopes the project.

Prioritization. Because PG&E is subject to annual spending limits dictated by the General Rate Case, CAISO-approved projects are considered by PG&E for prioritization, together with a broader list of non-CAISO projects, in its project execution schedule. In prioritizing projects, PG&E reconciles budget constraints with safety, load growth and reliability needs, as well as other factors, such as contractual obligations and state mandates. For example, load growth in certain areas may not materialize as quickly as assumed in CAISO planning, or wildfires may require pivoting to large safety-reform efforts. As a result of prioritization, some CAISO-approved projects are deferred to future years.

For instance, in 2023, an increased number of CAISO projects were deferred due to work reprioritization within PG&E. Reprioritization has been driven by two main factors. First, PG&E launched its Community Wildfire Safety Program in 2018 to respond to wildfire conditions due to climate change. Funding flowed to support hardening and undergrounding the distribution systems, installing weather stations and enhanced power line safety settings, the Public Safety Power Shutoff program, and other advanced tools and technologies like artificial intelligence and drones to automate fire detection and response. The Community Wildfire Safety Program, along with increased need for major storm response in recent years, has required significant financial and workforce resources. Second, significant inflation and supply chain delays have increased the cost and time to execute PG&E's work plan.

Execution: After a project is prioritized and allocated budget, execution commences. Execution of a project generally involves project kick-off and team assembly, design and permitting, and construction. These steps are further explained below (up to permitting).

1) During kick-off and team assembly, PG&E first must assign a project manager (PM) and assemble an internal team of subject matter experts (e.g., engineering, construction planning, environmental, land rights).

2) The team must hire the contractor(s), which requires preparing a Request for Proposal (RFP), soliciting proposals from contractors, a bidding process, selecting the contractor, and executing contracts through PG&E's Sourcing Department (which must review contractors for ISO 9001 safety grades or certifications, conduct cyber-security background checks, and complete other due diligence tasks).

3) Design and engineering must begin (generally performed by contractors, with internal oversight.)

4) At the same time, the environmental team (also supported by contractors) is mobilized to begin conducting studies and preparing information to be used to determine the initial project footprint and potentially-feasible alternatives, all of which will become part of the Proponent's Environmental Assessment (PEA).

5) A routing review must be performed for new (as opposed to existing) transmission lines.
6) Routing reviews include public outreach, since proceeding without public outreach could result in major feasibility issues or missed areas of controversy.
7) Design and environmental review, as they develop, must inform the selection of available alternatives and may change the proposed route or site location.
8) Federal, state, and local agencies must be consulted throughout the PEA development process, and their input may often drive further changes to the proposed project.

9) Design or engineering is generally at least 60% complete before PG&E is able to file a CPCN or PTC application. GO 131-D filing packages, including the largest effort – preparing the PEA, progress in parallel path with project design and usually take two years or more to complete due to the level and breadth of detail required by the Energy Division's *2019 Guidelines for Energy Projects Requiring CEQA Compliance* (2019 Guidelines).

Reassessment/Rescoping by CAISO. The annual CAISO TPP produces a list of approved projects that would meet a 10-year projection of demand in various zones throughout the state. The projects are identified based on reliability needs, policy goals, and ratepayer savings. The approved projects can range from low-risk projects that can be initiated within the next year to significant investments that are phased and have lead times of up to eight to 10 years. As part of the TPP, CAISO may adjust this project list based on load growth and evolving grid conditions. The CAISO may put projects on hold, cancel projects entirely, or recommend modifications to the original project scope (rescoping), and PG&E adapts its project execution schedules accordingly. If CAISO puts a project on hold, then PG&E may consequently defer execution of the project. For example, if CAISO determines that the in-service date of a project should be on year 5 following its approval of a project and it appears that permitting will not be required (e.g., a minor substation modification), then PG&E may not prioritize that project for execution until year 3 after CAISO approval. I Rescoping of a project could also delay execution of the project.

Example projects and associated factors that contributed to their planning and application timeline are provided in Table 1-b below.

TABLE 1-b		
Project Name	**Filing Information**	**Approximate Timeline and Contributing Factors**
Estrella Substation and Paso Robles Area Reinforcement Project	PTC: A.17-01-023 Filed January 2017	• CAISO approved this project in 2014 and awarded project to Horizon West Transmission (HWT) in March 2015. PG&E prioritized project (issued budget) in 2014, and began execution in 2015.

TABLE 1-b		
Project Name	**Filing Information**	**Approximate Timeline and Contributing Factors**
		• It took 22 months from the start of project execution to GO 131-D filing. Factors that contributed to this timeline are below: o 4 months to hire contractor for routing study; 1 year to complete public scoping and routing study (2015-2016) o 30% design completed in February 2016 (while PG&E typically files GO-131D applications upon 60% design or later, the PTC application here was filed based on 30% design because (1) it would have been very costly and time consuming to develop 60% design for multiple alternatives, and (2) PG&E's filing schedule was driven by HWT's schedule. o 4 months to hire PEA consultant; 1 year to prepare PTC application package (2016-2017) • It should be noted that the PTC application package for this project was prepared and filed prior to the Energy Division's 2019 Guidelines. Requirements under the 2019 Guidelines, such as providing project-level analysis for each alternative and alternative energy planning options, were retroactively applied to the application after filing. As of this March 8, 2024 response, 7 years after filing, the application is still undergoing review with the CPUC.
Plainfield Substation Upgrade Project (CAISO name: Vaca Dixon Area Reinforcement Prior CAISO name: Vaca – Davis Voltage Conversion Project)	PTC: Pre-filing occurred December 1, 2023 Formal filing expected in Q2 2024	• CAISO approved as Vaca – Davis Voltage Conversion Project in 2011. PG&E prioritized and started execution in 2012. In 2015, project was flagged as potentially needing rescoping after area load growth did not materialize, and it was put on hold. • CAISO officially paused this project in 2017 for rescoping. CAISO completed rescoping and approved new project (Vaca Dixon Area Reinforcement) in 2018. PG&E restarted execution in October 2018. • It took about 5 years and 2 months between CAISO re-approval and Draft PEA filing in December 2023. PG&E introduced the project to the CPUC in February Factors that contributed to this timeline include:

TABLE 1-b		
Project Name	**Filing Information**	**Approximate Timeline and Contributing Factors**
		○ It took 5 years to arrive at 60% design due to various design/engineering iterations. Designing the project was an iterative process, since initial designs had cascading operational consequences, which then had to be addressed. ○ It took 4 months to onboard Environmental contractor (by August 2021) after the project scope was sufficiently vetted for bidding purposes. ○ It took about 2 years and 2 months from then to submit the Draft PEA in December 2023, although PG&E introduced the project to CPUC in February 2023.
Northern San Joaquin 230 kV Transmission Project (formerly Lockeford-Lodi Area 230 kV Development)	CPCN: A.23-09-001 Filed September 2023	• CAISO approved in 2013 TPP. PG&E prioritized project in 2013, and began execution in 2013. • It took 9 years from the start of project execution to GO 131-D filing. Factors that contributed to this timeline are below: ○ Environmental support contract was executed in 2014. After public scoping efforts, first routing study was completed in 2017. ○ In 2017 and 2018, project was put on hold because CAISO re-scoped the project in its TPP. ○ In 2018, project resumed based on revised scope from CAISO, and prior scoping and routing studies needed to be re-done. Conclusions from the second routing study were determined in October 2019. • Once the conclusions of the second routing study were determined, assembling the formal application and PEA took nearly 4 years. Major factors contributing to this timeline included: ○ PG&E relied on Lodi Electric Utility (LEU) to contribute to project description and review drafted PEA. This coordination resulted in substantial additional time to prepare the PEA. ○ CPUC requested review of a battery alternative. This review added about 9 months of work to consider a battery

TABLE 1-b		
Project Name	**Filing Information**	**Approximate Timeline and Contributing Factors**
		alternative, hybrid battery alternative, and reconductoring approximately 20 miles of the existing 60 kV line. o A required NEPA component for the BLM segment of the project added to environmental review timeline. o Limited internal resources with conflicting priorities required added time to design and re-design various aspects of the project due to input from LEU. o It took 8 months from Draft PEA filing (January 2023) to formal application filing (September 2023) to respond to CPUC comments, as well as incorporate additional changes to scope of work (to 60kV line) and complete associated environmental review.

QUESTION 1.C

c. At what percentage of design completeness (e.g., 30% design, 60% design) does your company typically aim to file an application with the CPUC?

ANSWER 1.C

PG&E aims to submit applications to the CPUC after internal approval of 60% design.

QUESTION 1.D

d. At what point in the project planning and design process does your company engage contractors to support scoping, routing, and preparation of technical studies?

ANSWER 1.D

PG&E engages environmental contractors as early as possible in the planning and design process. Once a project is funded, as indicated in PG&E Data Response dated November 21, 2023, PG&E first must assign a PM and assemble an internal team. Next, the team hires the contractor(s). The hiring process includes preparing a RFP, soliciting proposals from contractors, a bidding process, selecting the contractor, and executing contracts through PG&E's Sourcing Department (which must review contractors for ISO 90011 safety grades or certifications, conduct cyber-security background checks, and complete other due diligence tasks). Hiring the contractor(s) for design and permitting is the longest lead item during project kick-off and team assembly, and can take up to 6 or 9 months for projects involving PTC and CPCN applications.

QUESTION 1.E

e. Please describe any ideas that could accelerate the internal utility planning and application process prior to the submittal of an application to the CPUC.

ANSWER 1.E

PG&E provided a response to this question in its Data Responses dated November 21, 2023. That response is reiterated below. Given the limited time for responding to the Energy Division's multiple data requests that were requested concurrently with the Order Instituting Rulemaking (OIR) proceedings, a comprehensive response to this question is not possible. However, PG&E offers the following initial suggestions, aimed at expediting the filing applications for TPP-approved projects at the CPUC.

Streamline Energy Division Hiring of Consultants. The utilities as well as Energy Division staff are often frustrated by the slow process required for State hiring. PG&E suggests exploring ways to expedite hiring CPUC consultants. Without CPUC consultants, the prefiling process is not effective.

Streamline PEA Guidelines and Checklist. When a project requires a CPUC permit, it can typically take one to three years (or longer as shown in Table 2) to prepare and file the Draft PEA, and another three to six months to formally file the permit application. The CPUC's =2019 Guidelines introduced procedural steps and burdensome additional information requirements that could be eliminated to expedite filing times. The Guidelines should not require more detail than is required for CEQA review. Some examples include:

- Streamline the 2019 Guidelines to reflect what is needed for California Environmental Quality Act (CEQA) review. While the 2019 Guidelines allow for deviation from the PEA Checklist, the Guidelines require the applicant to first obtain approval from Energy Division in writing before proceeding. This Guidelines provision creates added inefficiencies of time and effort and the outcome is not assured. PG&E's consultants are hired long before the CPUC has a team in place, so consultants preparing PEAs generally add most of these onerous requirements up front into their costs and schedules. PG&E attempts to temper the most onerous requests with hopes of deviating from provisions that do not make sense, but this takes time and effort.

- Utilize the CAISO TPPs in determining systems alternatives, leaving routing and location to be determined by the CPUC during CEQA review.

- Do not require more analysis on alternatives during CEQA review by the Commission than is required by CEQA. Do not require utilities to describe and evaluate all alternatives to the same level of detail as the proposed project. Use common sense and overviews; if a project alternative is infeasible, do not require discussions beyond why the project is infeasible.

Section 15126.6(d) of the CEQA Guidelines states that, "The Environmental Impact Report (EIR) shall include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project… If an alternative would cause one or more significant effects in addition to those that would be caused by the project as proposed, the significant effects of the alternative shall be discussed, but in less detail than the significant effects of the project as proposed project."

- Do not require utilities to submit detailed information, including Geographic information Systems (GIS) data, on the transmission and possibly distribution system to which the proposed project would interconnect or on the subject substation/transmission line beyond what is required for CEQA review. This information is rarely needed to assess impacts or alternatives and often must be submitted confidentially due to security concerns.

  Section 15124 of the CEQA Guidelines states, "…the description of the project… should not supply extensive detail beyond that needed for evaluation and review of the environmental impact." The PEA Checklist requests data that is beyond what is required to assess impacts of the project.

- Large, blanket buffers should be removed as they are often not appropriate for a specific project. For example, landscape units within a 5-mile buffer of the project, or greater if necessary, are to be identified and assessed. Biological surveys must extend 1,000 feet all directions from the project boundary, even when no impacts would occur at that distance. Wetland delineations are required out to 1,000 feet, and must be agency verified (which is not possible when no wetland permit is being sought). A Phase I Environmental Site Assessment (ESA) required for entire project area, even for linear, overhead projects where such documents are not relevant. Values at risk (including structures, habitats, utility infrastructure and other items that will burn in a wildfire) within 1,000 feet of the project are required to be identified and assessed.

Work with CAISO to Develop Criteria When Siting Third-Party Generation Facilities. Third-party generation facilities to which utilities must interconnect are sometimes sited at substantial distances from feasible interconnection points, or are designed to interconnect with large PG&E substations from the wrong direction, causing engineering and land-use conflicts. Consequently, utilities must build interconnection facilities that can be several miles long. The utilities and CPUC could work with CAISO to develop criteria for siting third party generation facilities, to address these concerns. If the generation facilities were sited such that the interconnection facility would be a short connection, design and permitting would be simplified. Additionally, siting interconnection facilities at shorter distances from feasible interconnection points reduces design uncertainties of the interconnection facility, allowing more accurate descriptions of PG&E's facilities in the CEQA documentation for the third-party generation facility and thereby expediting CPUC and resource-agency permitting.

PACIFIC GAS AND ELECTRIC COMPANY
GO 131-D Update and Amend OIR
Rulemaking 23-05-018
Data Response

PG&E Data Request No.:	ED_001-Q002		
PG&E File Name:	GO-131-D-UpdateandAmendOIR_DR_ED_001-Q002		
Request Date:	January 30, 2024	Requester DR No.:	001
Date Sent:	March 8, 2024	Requesting Party:	Energy Division
PG&E Witness:		Requester:	Tommy Alexander

SUBJECT: R.23-05-018 DATA REQUEST 01 - GO 131 UPDATE PROCEEDING

QUESTION 2.A

2. Please answer the following questions regarding application filing and pre-filing review:

a. Once a project is approved by CAISO, should the CPUC require the project proponent to file an application within a specified time window after CAISO approval (e.g., within one year) or within a specified time window prior to the required or forecasted in-service date (e.g., two years prior to the in-service date)? Alternatively, is it feasible to institute different filing deadlines based on project type and complexity? Please explain.

ANSWER 2.A

a. No. The CPUC should not require the project proponent to file an application within a specified time window after CAISO approval or relative to in-service dates. As explained in PG&E's November 21, 2023 response and in Response 1.b, there are dynamic factors that affect the timeline to filing. These dynamic factors include reprioritization of projects when there are competing priorities and limited funding, execution tasks and their time requirements, and project pausing projects if CAISO rescopes them in the TPP. Further, the timelines involved with these dynamic factors can vary depending on the unique circumstance of each project. Table 1.b provides specific examples of how these dynamic factors, as well as project-specific circumstances, can result in varying timelines between CAISO approval and General Order (GO) 131-D filings. Imposing unilateral timelines would fail to account for unique circumstances of each project.

QUESTION 2.B

b. Are there modifications to the pre-filing review process or application process that would incentivize applicants to initiate pre-filing consultation with the CPUC earlier in the project design process? Please explain.

ANSWER 2.B

The Energy Division's 2019 Guidelines introduced procedural steps and burdensome additional information requirements that could be eliminated to expedite both prefiling and formal filing times. (Various requirements in the 2019 Guidelines go above and beyond what is required under CEQA.) It takes a large amount of planning to prepare a project for presentation to the CPUC, and the 2019 Guidelines have substantially expanded this effort. PG&E has provided some suggestions on how to streamline the 2019 Guidelines in our Data Responses dated November 21, 2023. That response is reiterated under Response 1.e of this document.

The Energy Division's 2019 Guidelines state that utilities "will commence pre-filing consultation no less than 6 months prior to application filing at the CPUC." Six months is already a significant amount of time prior to filing, and requiring project information submittal earlier than 6 months from filing would further extend an already extended process. The prefiling process that was introduced by the 2019 Guidelines has added a 6-month-long step prior to formal filing. As evidenced by project examples such as Northern San Joaquin 230 kV Transmission Project (see Table 1.b), it realistically can take longer than 6 months for Energy Division staff to review the Draft PEA and for PG&E to revise the documentation based on the Energy Division comments, prior to formal filing. In an effort to expedite the prefiling process, PG&E has opted to submit Draft PEA sections individually, as they are completed, and the CPUC has as well accepted individual section submittals.

PG&E aims to submit the Draft PEA upon or after 60% design, to minimize potential changes to the project description and analysis post submittal. It generally would not be prudent to provide project information or have the CPUC start environmental review earlier because doing so could result in premature review and wasteful use of proponent and agency effort, time, and budget. As an example, the Northern San Joaquin 230 kV Transmission Project was rescoped by CAISO after PG&E completed its first round of scoping and routing efforts (see Table 1.b). As a result, scoping and routing was redone. If PG&E had submitted its first routing study and associated information to the CPUC for review prior to CAISO's rescoping, then both PG&E and the CPUC would have wasted effort, time, and money in reviewing the information.

Currently, PG&E already provides project information to the CPUC in advance of pre-filing, in quarterly and monthly meetings, and in regularly submitted reports, including the Stakeholder Transmission Asset Review (STAR) Process, CAISO Transmission Development Forum (TDF), and Assembly Bill (AB) 970 reports. Please see Response 2.c below for further information.

QUESTION 2.C

c. Are there other modifications to GO 131-D that could enable applicants to provide project information (e.g., in-service date, project objective and design, potentially feasible siting/routing) to the CPUC on an expedited basis for CAISO-approved projects, or that could otherwise enable the CPUC to begin environmental review sooner? To what extent can this information be provided prior to application filing via the Transmission Project Review (TPR) Process or via existing recurring meetings between IOUs and CPUC staff? Please explain.

ANSWER 2.C

Please see Response 3.b. In addition, please see the below list of avenues through which PG&E already provides advance project information to the CPUC. PG&E believes this information is ample, and can be used by the CPUC for advance planning. No additional advance information is warranted. Please note that each request for data requires staffing, costs, and effort, diverting resources from actual permit preparation.

1) Quarterly meetings
    - Attended by PG&E Asset Strategy and Environmental Management teams, CPUC Energy Division.
    - Information provided includes high-level information on project need, project route, project status, permit filing status, and projected annual and total spend for in-flight and projected filings.
2) Monthly meetings
    - Attended by PG&E Environmental Management and CPUC Energy Division
    - Information provided includes 4-month look ahead of projected NOC filings, 2-year look ahead of projected PTC/CPCN filings, and a list of submitted and pending filings. For each upcoming filing, a high-level project description, county, projected filing dates, and filing type are provided.
    - As requested by the Energy Division on February 16, 2024, PG&E has agreed to include projected in-service dates in the monthly meetings.
3) AB 970 Report
    - Provided quarterly
    - Information provided includes high level project description, project purpose and benefit, PG&E internal accounting information, project cost, project status, construction start date, and in-service date
    - The above information is provided for capacity projects, reconductoring of transmission lines, transmission transformer replacements, network upgrades, and interconnection of generation and load facilities
4) CAISO Transmission Development Forum Report
    - Provided bi-annually starting in 2024 (was provided quarterly prior)
    - Information provided includes expected in-service dates upon TPP approval and upon each subsequent, quarterly TDF
    - The above information is provided for all CAISO-approved network upgrades and TPP projects.
5) Stakeholder Transmission Asset Review Submittal
    - Provided bi-annually
    - Information provided includes a Project Data Spreadsheet with 63 data fields as defined by PG&E's Federal Energy Regulatory Commission (FERC) STAR Tariff. The data fields include provide project scope and location, GO 131-D permit requirements and status, construction

status, and in-service date information, in addition to other information. Information is discussed at a a Stakeholder Meeting, where there is opportunity for data requests.

- The above information is provided for FERC-jurisdictional electric transmission capital projects at the Planning Order level with a cost greater than $1 million.

PACIFIC GAS AND ELECTRIC COMPANY
GO 131-D Update and Amend OIR
Rulemaking 23-05-018
Data Response

PG&E Data Request No.:	ED_001-Q006		
PG&E File Name:	GO-131-D-UpdateandAmendOIR_DR_ED_001-Q006		
Request Date:	January 30, 2024	Requester DR No.:	001
Date Sent:	March 8, 2024	Requesting Party:	Energy Division
PG&E Witness:		Requester:	Tommy Alexander

SUBJECT: R.23-05-018 DATA REQUEST 01 - GO 131 UPDATE PROCEEDING

QUESTION 6

6. Of all the transmission projects approved by CAISO in the past five years, is there a subset of projects that should be prioritized (e.g., policy-driven transmission projects) for California to reach its emission reduction goals? Please explain.

ANSWER 6

PG&E has an internal prioritization process that shifts funding to the highest needs and regularly reassesses these issues. (See response to Question 1.B.) But we are assuming this question refers to prioritization by the CPUC in its permitting process as proposed by the Public Advocates Office (PAO) in this proceeding. PG&E believes it would be a mistake to prioritize projects through this process.

In the past five TPP cycles (since 2018-2019) the CAISO has approved nearly 60 transmission capacity projects. Project prioritization would add a complicated and controversial step to the permitting process and one that would lead to reduced flexibility. Most importantly, PG&E believes that the unprioritized projects could be neglected, which in turn could affect system planning, compliance, and reliability to customers.

Rather than adding a process that would identify policy-driven transmission projects for prioritization, PG&E believes the CPUC should speed up the permitting process for *all* projects by avoiding duplication and increasing efficiencies in the CPUC permitting process.

QUESTION 6.A

a. Would prioritizing these projects help streamline permitting? If so, can this be accomplished by changes to GO 131-D in Phase 2 of this proceeding?

ANSWER 6.A

Please see response 6. Prioritizing TPP projects is not the answer to the CPUC's permitting delays. Prioritizing TPP projects in the CPUC permitting queue could result in controversy and neglect of other, important projects. PG&E's non-TPP projects include, but are not limited to, compliance work (such as GO 96 or NERC clearance projects), work at the request of others (such as relocation projects to accommodate California Department of Transportation (Caltrans) road work), reliability and safety projects (such as structure replacements), and system planning projects. To de-prioritize these projects would inevitably be harmful to electric customers.

QUESTION 6.B

a. To what extent could more detailed project routing and siting work coupled with feasibility studies and high-level environmental constraint analyses conducted up front during the CAISO transmission project identification and planning processes streamline subsequent State siting approvals?

ANSWER 6.B

PG&E does not recommend that siting/routing or environmental assessments be conducted at the TPP stage for various reasons.

First, as discussed under Response 3.e, the TPP process has a very compressed timeline in which PG&E is required to perform many project development activities in an expedited fashion, to be able to submit project proposals to the CAISO. There would be no or insufficient time during the TPP for either PG&E or the CAISO to include more detailed project routing and siting work coupled with feasibility studies and environmental constraint analyses.

Second, performing routing studies or high-level analysis at the TPP stage, while extending the TPP process, would bring little to no time savings downstream. Further, starting routing/siting at the TPP stage would result in inefficient, stop-and-go design and environmental review that would likely extend the overall process. When PG&E prioritizes and begins execution of its project, high-level desktop review is conducted as early as possible to identify major environmental constraints and to inform the preliminary permitting path for the project. If routing and siting work, coupled with feasibility studies and environmental constraint analyses were to be conducted during the earlier TPP phase, the results of these studies would need to be reviewed and verified by the project team anyway.

Third, as demonstrated in Table 1-b, CAISO may pause and rescope a project after initial TPP approval and after PG&E commenced project execution. In these cases, conducting more detailed project routing and siting work, coupled with feasibility studies and high-level environmental constraint analyses at the TPP stage, would be premature and a wasted effort if the project scope then changed sufficiently or if so much time passed that environmental analyses would need to be redone.

Finally, CAISO's role is to plan and operate the grid as well as to run the wholesale energy market in the region to maintain a reliable and efficient grid; performing environmental review or routing studies is not the role of CAISO or CAISO-owned processes such as the TPP, which must accomplish many other aspects of planning the grid in an already compressed timeline.

QUESTION 6.C

c. Are there other changes to the electric transmission planning and permitting process that would be necessary to achieve State emission reduction goals, e.g., new legislation or changes to GO 96-B? Please describe any recommended changes in detail.

ANSWER 6.C

c. Please see Response 1.e.

QUESTION 6.D

d. More broadly, is there an optimal way to sequence the build-out of the grid? Are there workforce or supply chain constraints that prevent projects from being constructed simultaneously?

ANSWER 6.D

d. This seems to be a question to direct at the CAISO, which is responsible for planning build-out of the grid. For utility construction projects, there are various factors that need to be considered when scheduling construction, or that can impact construction schedules. First and foremost, a transmission line must be turned off prior to construction for crew and public safety (i.e. clearances); turning off a transmission line that serves a large population requires complex, advance planning to divert electricity flow to other transmission lines and prevent service interruptions.[1] During peak seasons when electricity is in high demand, it becomes more difficult to schedule clearances. Clearance limitations alone can prevent construction projects from occurring simultaneously.

In addition, clearance limitations need to be juggled with other limitations, such as seasonal work restrictions and weather conditions. Where transmission lines transect environmentally sensitive areas, seasonal work restrictions limit construction to certain windows of time. Severe weather and snow conditions can preclude construction in certain areas, especially mountainous or windy areas.

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1 Given the complexity of clearance scheduling, PG&E holds quarterly Transmission Operations Planning (TOPS) meetings to review project scopes and schedules, various clearances required, duration of clearance, clearance sequencing, etc. PG&E's Grid Operations group must also evaluate the impact of clearances against the grid, to ensure adequate load is available to serve the customer base.

Wildfires and severe storms can divert resources away from construction projects and interrupt construction schedules.

Additionally, yes, supply chain issues (e.g. steel) have led to build-out issues, as construction schedules and clearances need to be adjusted accordingly. Please see the response to Question 5 for information on lead times to procure materials and limitations on when materials should be ordered.

PACIFIC GAS AND ELECTRIC COMPANY
GO 131-D Update and Amend OIR
Rulemaking 23-05-018
Data Response

PG&E Data Request No.:	ED_001-Q007		
PG&E File Name:	GO-131-D-UpdateandAmendOIR_DR_ED_001-Q007		
Request Date:	January 30, 2024	Requester DR No.:	001
Date Sent:	March 8, 2024	Requesting Party:	Energy Division
PG&E Witness:		Requester:	Tommy Alexander

SUBJECT: R.23-05-018 DATA REQUEST 01 - GO 131 UPDATE PROCEEDING

QUESTION 007

In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023, settling parties proposed adding "power line facilities or substations" to the second clause of section III.B.1.g. Of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, how many are located within a "utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies"? Please provide a list of these projects and the applicable utility corridor(s). Of these projects, how many currently qualify for exemption "g", and how many would qualify for exemption "g" if the settlement agreement suggestion were to be implemented? Do the parties anticipate other, future utility corridors that would impact the use of exemption "g"? Please explain.

ANSWER 007

The recommended addition was intended solely for grammatical purposes and was not intended to — and PG&E does not believe that it would — change the scope or the number and types of projects that would qualify under the second exemption in Section III.B.1.g. Of the referenced CAISO-approved projects, none were noticed under the utility corridor exemption in Section III.B.1.g and, without having extensively researched the question, PG&E is not presently aware of any that are located within a utility corridor designated, precisely mapped, and officially adopted pursuant to law by federal, state, or local agencies. At this time, PG&E is not aware of other, future utility corridors that would impact the use of exemption "g."

March 8, 2024

Tommy Alexander
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California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: R.23-05-018 Data Request 01 – GO 131 Update Proceeding

Mr. Alexander

On January 29, 2024, California Public Utilities Commission (CPUC) staff emailed LS Power Grid California, LLC (LSPGC) and the other parties in Phase 2 of the General Order (GO) 131-D update proceeding (R.23-05-018) with a data request addressing a broad range of topics relevant to the proceeding. The following sections detail LSPGC's responses to the data request.

R.23-05-018 Data Request 01:

1. Please answer the following questions regarding the internal utility planning, design, and application process for electrical transmission projects:
   a. On average, how long does it take for a project to be submitted to the CPUC via Certificate of Public Convenience and Necessity (CPCN) or Permit to Construct (PTC) application after it has been approved in a California Independent System Operator (CAISO) Transmission Plan? Provide the data used to calculate the average.

      LSPGC Response: On average, an application submittal takes approximately 16 months based on LSPGC's recent experience. The table below shows six recent LSPGC projects and their submittal dates/anticipated submittal dates.

Project Name – Application Type	CAISO Approval Date	Application Submittal/Anticipated Submittal Date	Elapsed Time
Gates 500 kilovolt (kV) Dynamic Reactive Support Project - PTC	January 2020	February 2021	13 months
Round Mountain 500 kV Dynamic Reactive Support Project - PTC	February 2020	April 2022	26 months
Collinsville 500 kV Substation Project - CPCN	January 2023	Anticipated Q2 2024	16 months
Manning 500 kV Substation Project- CPCN	January 2023	Anticipated Q2 2024	16 months

Metcalf-San Jose B High Voltage Direct Current (HVDC) Project - CPCN	March 2023	Anticipated Q2 2024	14 months
Newark-NRS HVDC Project - CPCN	March 2023	Anticipated Q2 2024	15 months

b. Please explain in detail the key time components in your company's internal planning and application process for electric transmission projects. Provide at least three relevant examples from the last ten years that illustrate a representative range of cases (i.e., the middle and tail ends of the range used to calculate the requested average). For each example, discuss the factors that contributed to the duration of each component of the internal planning and application process.

LSPGC Response: There are many factors that contribute to the internal planning process, including, but not limited to: complexity of scope, detailed design, project location and features, potential landowners, routing and siting, agencies/stakeholders, environmental scoping and investigations, and in-service date.

Detailed design, landowner and stakeholder outreach, and environmental scoping activities begin shortly after a project is selected in CAISO's Transmission Plan. These factors play a large role in the key timing behind the submittal of any application to the CPUC. One of the most critical components to any transmission project is helping to ensure that the landowners and other stakeholders directly affected by the project are informed early and consulted on a regular basis. This process takes months to years and typically proceeds in parallel with the project proponent's efforts to secure land rights and easements for the ultimate construction of any project. However, in the early stages of development, prior to an application submittal, key purposes of landowner and stakeholder outreach are to identify any constraints and opportunities, determine landowner willingness to participate in the project, and solicit feedback from stakeholders to improve the project. This helps inform the proponent which in turn feeds into detailed design, updated routing and siting, and environmental review.

In tandem with landowner outreach, the project proponent typically undertakes an updated routing and siting assessment for the project. This assessment incorporates alternatives identified by the proponent and refines or adds to those alternatives based on the stakeholder outreach described above. This assessment of routing and siting helps the proponent to ultimately select a proposed route and location of the project while providing potential alternatives for review. On average, this analysis takes approximately six months to complete, as information from landowner outreach and additional research into the project area feeds into this updated routing and siting approach.

Simultaneous with the routing and siting assessment, environmental scoping and investigations of the project area are conducted. The environmental review and development of the Proponent's Environmental

Assessment (PEA) is an intensive process which takes information from the routing and siting assessment and begins analyzing the impacts to resources in accordance with CPUC's California Environmental Quality Act (CEQA) guidance. Detailed design feeds into the PEA, as impacts from the substation location to each individual transmission structure are evaluated and quantified to determine if a resource is impacted and to what extent. Development of the PEA, depending on complexity of the project and timing of design, takes approximately 10 to 12 months.

Preliminary design occurs once a preferred route and site are selected. This design takes into account any geotechnical information, the preferred route, and items identified in the routing and siting (e.g., distance to airports, roadway crossings, terrain) and finds the optimal foundations for structures, structure types, conductor types, optimal substation design, and preferred access roads. Applications to the CPUC are typically based on a preliminary design, up to 30% complete, which typically requires approximately 10 to 12 months to complete.

Examples, as requested, include the six projects identified in Question 1 above. The average time to submit, including anticipated submittal, is 16 months. The applications for the Manning, Collinsville, Metcalf, and Newark Projects are anticipated to be filed within a 14-to-16-month range. These projects involve complex biological resources, multiple landowners, and complex design. An example of the faster end of the scale includes the Gates Substation Project which has fewer biological concerns and landowners, facilitating a quicker preparation time the application submittal. This project falls within the 13-month timeframe.

An example on the slower end of the scale includes the Round Mountain Project, which took approximately 26 months. This project had biological resources at the site requiring site specific surveys during specific times of year, increasing the delay of the submittal. The Round Mountain Project also had more complicated interconnection and distribution facilities and offsite system upgrades which are covered in the CEQA review and required design input from the interconnecting utility. Furthermore, the Round Mountain Project was subject to CAISO directed changes which added rework to the design and PEA development.

c. At what percentage of design completeness (e.g., 30% design, 60% design) does your company typically aim to file an application with the CPUC?

LSPGC Response: LSPGC identifies routing and siting options during the initial proposal solicitation from CAISO. Upon selection by CAISO, LSPGC begins preliminary design and updated routing and siting to as described in response to data request 1 (b). LSPGC typically aims to submit a completed application and PEA with approximately 30% of the preliminary design completed.

d. At what point in the project planning and design process does your company engage contractors to support scoping, routing, and preparation of technical studies?

LSPGC Response: LSPGC typically engages contractors to support scoping, routing, and preparation of technical studies during the initial proposal solicitation from CAISO. Work with the contractors continues once LSPGC is selected by CAISO and proceeds throughout the permitting process.

e. Please describe any ideas that could accelerate the internal utility planning and application process prior to the submittal of an application to the CPUC.

LSPGC Response: Landowner property access permissions are typically the longest lead item when it comes to facilitating routing discussions and technical studies. Thus, expedited opportunities to access properties within routing and siting corridors could help accelerate the internal planning and application process. Such opportunities could be provided by legislative action (e.g., legislation could allow a public utility to access a property for non-invasive access and survey with 15 days advance written notice). This opportunity would primarily assist projects competitively offered by CAISO. In addition, CPUC review of draft PEA documents should be limited to 30 days.

2. Please answer the following questions regarding application filing and pre-filing review:
   a. Once a project is approved by CAISO, should the CPUC require the project proponent to file an application within a specified time window after CAISO approval (e.g., within one year) or within a specified time window prior to the required or forecasted in-service date (e.g., two years prior to the in-service date)? Alternatively, is it feasible to institute different filing deadlines based on project type and complexity? Please explain.

LSPGC Response: The time and effort required to prepare an application varies greatly depending on a multitude of factors, such as the size and complexity of the project, the geographic location, the environmental resources present in the area, the project proponent's ability to access lands crossed by the project, the process for gathering stakeholder input, and the availability of support from environmental contractors, engineering contractors, construction contractors, and equipment providers. Project proponents and CAISO take these factors into account when determining milestone dates for projects set forth in the Approved Project Sponsor Agreements (APSAs) between project proponents and CAISO. Since achieving the in-service date (including all intermediate steps such as application preparation and permit issuance by CPUC) for a project is addressed contractually between the project proponent and CAISO, CPUC's imposition of an application submittal deadline would be unnecessary and would subvert CAISO's ability to manage its process for bringing grid assets online. As such, a CPUC-imposed application submittal deadline, whether implemented as a one-size-fits-all deadline or as a deadline customized by project type and complexity, would be inappropriate.

Moreover, requiring a deadline for application submittal would likely yield negative returns in some circumstances. If an application submittal deadline was required by CPUC, project proponents might be incentivized to sacrifice application completeness or quality in the interest of meeting the deadline.

b. Are there modifications to the pre-filing review process or application process that would incentivize applicants to initiate pre-filing consultation with the CPUC earlier in the project design process? Please explain.

LSPGC Response: Since the bulk of the CEQA analysis typically precedes CPUC's consideration of a project proponent's application for a PTC or CPCN, the CPUC's CEQA guidance is relevant to discussions of pre-filing consultation. With respect to early consultation, the CPUC's CEQA guidance states the following:

"During Pre-filing Consultation, Applicants and CPUC Staff meet to discuss the upcoming application. Successful projects will commence Pre-filing Consultation no less than six months prior to application filing at the CPUC. When the application is formally filed at the CPUC, the Application and the PEA are submitted to the CPUC Docket Office" (CPUC, CEQA Pre-filing Guidelines PEA Checklist, 2019)

As such, project proponents operating under the CEQA guidance already have reason to initiate early pre-filing consultation with CPUC. Additionally, project proponents are typically incentivized by internal schedules and required in-service dates to begin discussions with the CPUC shortly after CAISO selects a project. Such early consultation initiated by a project proponent allows the CPUC sufficient time to identify appropriate project management teams, CEQA review consultants, and timelines to efficiently process an application.

To further incentivize early pre-filing consultation for projects competitively awarded by CAISO, the CPUC could offer priority status with firm execution and completion schedules for both CEQA review and application processing after CEQA is complete for proponents that initiate pre-filing consultations within 60 days of award by CAISO. The CPUC would need to create a mechanism to incentivize the third-party CEQA consultants to meet the time schedule. Further, applicants should have the opportunity to file a draft CEQA document in lieu of a PEA, which would potentially save a year.

c. Are there other modifications to GO 131-D that could enable applicants to provide project information (e.g., in-service date, project objective and design, potentially feasible siting/routing) to the CPUC on an expedited basis for CAISO-approved projects, or that could otherwise enable the CPUC to begin environmental review sooner? To what extent can this information be provided prior to application filing via the Transmission Project Review (TPR) Process or via existing recurring meetings between IOUs and CPUC staff? Please explain.

LSPGC Response: As stated in response to Question 2.a, the time and effort required to prepare an application varies greatly depending on a multitude of factors, such as the size and complexity of the project, the geographic location, the environmental resources present in the area, the project proponent's ability to access lands crossed by the project, the process for gathering stakeholder input, and the availability of support from environmental contractors, engineering contractors, construction contractors, and equipment providers. While early information sharing may seem prudent, design is preliminary during the pre-filing process. Thus, supplying information on preliminary design or routing early on in the process to begin environmental review may result in rework and reanalysis of impacts when the complete application is submitted. LSPGC does not recommend modifications to GO 131-D to provide the CPUC with project data prior to a pre-filing process.

3. Please answer the following questions regarding the provision of cost estimates:
   a. Please explain in detail the point in your internal planning process at which cost estimates are typically submitted to the CPUC, when required. What actions are required for applicants to provide an estimated cost for PTC projects and a statement of why the project is needed? What challenges or barriers do applicants encounter during this process? Can they be addressed by the Commission, and if so, in what ways can they be addressed?

      LSPGC Response: No Response.

   b. Would showing that a project was selected as a result of a competitive process at the CAISO, which includes a cost cap, satisfy requirements to demonstrate the cost and need for CPCN and PTC projects?

      LSPGC Response: Per Section IX.B.1.f of GO 131-D, a cost estimate and economic analysis is not required for a PTC application; thus, this question does not appear applicable to PTC projects. For a CPCN application, GO 131-D states in Section IX.A.1.d that a detailed statement of the estimated cost of the proposed facilities is required. (CPUC, General Order 131-D, 1995)

      As part of the competitive solicitation process, in which CAISO selects and awards the project to an applicant, CAISO takes into account the costs of each project it evaluates. CAISO always places a heavy emphasis on cost savings and highly values projects that aim to reduce cost. As part of the competitive solicitation process, the bidders are required to submit confidential detailed cost estimates for their respective proposed projects, ensuring that CAISO has a robust set of cost data available during CAISO's decision process for a comprehensive sensitivity analysis to consider risks of cost overruns. After selection, the proponent works with the CAISO to finalize the APSA and ensure that CAISO and the proponent are in agreement on costs for the project. Stating the project was selected as a result of a competitive solicitation process, which incorporates a detailed review and vetting of the cost, should provide enough rationale to justify the cost for a CPCN project. Additionally, while cost containment provisions add certainty and confidence to ultimate ratepayer impacts, they should not be a necessary condition for the cost of a CPCN project to be justified since CAISO has the expertise to evaluate project costs and select projects that best serve the economic interests of ratepayers.

   c. To what extent are any delays in the provision of cost estimates attributable to the design and planning of interconnection to the distribution system? Please explain and provide examples.

LSPGC Response: This question is not applicable for competitively awarded projects through CAISO, which is where LSPGC's experience lies.

d. Please also explain the typical time periods for cost estimates to reach different levels of reliability (e.g., 100% contingency, 50% contingency, 25% contingency), and what factors may impact these time periods.

LSPGC Response: This question is not applicable for competitively awarded projects through CAISO, which is where LSPGC's experience lies.

e. When and why do costs submitted to the CPUC in the application process differ from costs identified in the CAISO Transmission Plan? Please provide a range of examples of such projects and explain what caused the difference.

LSPGC Response: Both projects for which LSPGC has submitted applications to the CPUC were PTC applications that did not require detailed cost estimates. Thus, LSPGC is not able to provide a range of examples for differences between CAISO planning estimates and CPUC application cost information.

4. Please answer the following questions regarding the CPCN and PTC exemption criteria:
   a. Would adding specificity to the CPCN and PTC exemption criteria (e.g., including a non-exhaustive list of examples of "equivalent facilities or structures", "minor relocation", and "accessories") increase applicant certainty regarding whether an exemption would apply and/or increase the number of projects for which an exemption may apply? If so, please provide specific suggestions (e.g., converting existing lattice towers or wood poles to steel monopoles no more than X percent taller than the existing structures). If additional terms are proposed, please provide definitions.

LSPGC Response: LSPGC believes that adding a non-exhaustive list to the CPCN and PTC exemption criteria could prove prudent and add additional context, clarity, and examples for proper implementation. An example of a non-exhaustive list for "equivalent facilities or structures" might include: reconductoring existing structures; modifications to existing structures to accommodate additional conductors; or other actions with similar impacts; an example of a non-exhaustive list for "minor relocation" might include: minor and *de minimis* relocations of existing structures; modification of existing facilities within existing ROW; or other actions with similar impacts; an example of a non-exhaustive list for "accessories" might include: non-wire alternatives; substation equipment modifications; or other actions with similar impacts.

   b. Would adding specificity to the term "minor relocation of existing power line facilities" in Section III.A (for CPCN exemptions) increase advice letter filings and reduce application filings (e.g., by increasing the number of projects that are eligible for PTC exemptions 1b, 1c, and 1e)? Please explain.

LSPGC Response: Adding specificity to the term "minor relocation of existing power line facilities" would not increase the amount of advice letter filings. The rationale behind this statement stems from SB 529 and the language approved in Phase 1. The language allows for electrical transmission lines or electrical transmission facilities, irrespective of if the line or facility is over 200 kV, to utilize exemptions in Section III.B.1, if the line or facility meets the language defined in Phase 1. Thus, this specificity would become a moot point, as there is a specified version of the language in Section III.B.1.C "the minor relocation of existing power line facilities up to 2,000 feet in length, or the inter-setting of additional support between existing support structures" which implies length of facilities and additional inter-setting of structures (CPUC, General Order 131-D, 1995). Therefore, it would be implied that if an electrical transmission line or electrical transmission facility would meet the exemption in Section III.A, and would be covered under the language in Section III.B.1.c and already be eligible for an advice letter. Thus, the addition of specificity is not required in Section III.A.

c. Would reformatting the CPCN exemptions in GO 131-D Section III.A as an ordered list, similar to the existing list of PTC exemptions in Section III.B.1, increase applicant certainty regarding whether an exemption would apply?

    LSPGC Response: Yes, itemizing a list of exemptions, as in Section III.B.1, within Section III.A would increase certainty on if and when an exemption would apply. This ordered list, as in Section III.B.1, helps facilitate discussions and interpretations, while making the exemptions clear and defined within their own individual context. Thus, it stands to reason that a reorganization of the list described in Section III.A into a similar list as Section III.B.1 would allow the same benefits and discussion, by adding clarity and individual context.

d. Are there any other pros and cons to making such modifications? Please explain.

    LSPGC Response: An ordering or listing of the exemptions under Section III.A can be helpful to: 1) Modify GO 131-D to have consistent content between sections, such as Section III.A and Section III.B, read similarly. This facilitates ease of understanding for the general public. 2) Create a well-defined context for each exemption. The purpose of Phase 2 is to create a well-defined list, definition, and/or example of the new language approved in Phase 1. By modifying Section III.A into an organized list, it allows project proponents to contextualize individual criteria which may be applicable to a given project.

5. What are the current typical lead times for obtaining equipment critically necessary to complete transmission projects (such as transformers, circuit breakers, busbars, conductors, etc.)? What factors influence the calculation of estimated lead times? Are there any emerging issues (e.g., supply chain) that will significantly impact future lead times? What actions can transmission developers take to expedite timelines for obtaining equipment? Could explicit authorization to procure long-lead-time equipment expedite transmission projects?

    LSPGC Response: Lead time to obtain electrical equipment critically necessary to complete transmission and substation projects can vary; however, as a generalization, multiple years (over 12 months, typically in a range of 20 to 24 months; in some cases, up to six years) are expected for long-lead items such as transformers and reactors. Air insulated breakers currently have lead times of three to four years.

In recent times when increased global demand for transmission infrastructure components has outpaced global manufacturing supply, there are numerous factors that drive lead times for critical equipment. These factors may include and are not limited to, labor and equipment shortages, raw material and commodity shortages, manufacturing delays, transportation shortages, and storage space and other logistical constraints.

Issues that have proven themselves long lasting include supply chain issues and an increase in demand worldwide. Across the industry, there are numerous new legislative actions and policies which aim to increase renewable energy capacity and bolster or expand existing electrical grids. Due to these demands, lead times for obtaining critical equipment has dramatically increased in recent years. Combined with the global supply chain disruption in 2020 and embargoes on targeted countries, obtaining critical equipment in the short term is typically not possible.

6. Of all the transmission projects approved by CAISO in the past five years, is there a subset of projects that should be prioritized (e.g., policy-driven transmission projects) for California to reach its emission reduction goals? Please explain.

   LSPGC Response: Reliability projects and policy-driven projects are important to California's effort to reach its emission reduction goals. Without reliability projects, the grid may not be strong enough to account for the increased renewables coming into the energy system. Reliability and policy-driven projects are equally important to California's goals and should be internally prioritized equally.

   a. Would prioritizing these projects help streamline permitting? If so, can this be accomplished by changes to GO 131-D in Phase 2 of this proceeding?

      LSPGC Response: LSPGC does not propose additional modifications in Phase 2 to prioritize reliability or policy-driven projects as both types of projects are equally important.

   b. To what extent could more detailed project routing and siting work coupled with feasibility studies and high-level environmental constraint analyses conducted up front during the CAISO transmission project identification and planning processes streamline subsequent State siting approvals?

      LSPGC Response: While conducting additional detailed routing and siting, feasibility studies, and more high-level environmental constraints analysis during the CAISO planning process might potentially speed up the rate at which an approved project sponsor would be ready to file an application at the CPUC, the cost and time to conduct these studies is not feasible until CAISO selects the Approved Project Sponsor. The losing bidders have no mechanism to recover the cost of trying to advance the project.

      A mechanism that would help streamline the CEQA process would be to allow the proponent to draft the CEQA document for the project and attach that as part of the application. Allowing the proponent to draft the CEQA document would save at least one year from the overall permitting timeline. In addition, the CPUC should retain and activate consultants early in the process, shortly after CAISO selection and initial meetings with the proponent. This would allow the consultant and the CPUC to review the CAISO documents and proposals, increasing familiarity with the project prior to pre-filing. These processes would remove the need for a PEA and streamline the CEQA certification process. LSPGC recommends the CPUC include a mechanism in Phase 2 to allow for the proponent to draft the CEQA document and to have the CPUC retain and activate consultants early on in the process after CAISO selection.

c. Are there other changes to the electric transmission planning and permitting process that would be necessary to achieve State emission reduction goals, e.g., new legislation or changes to GO 96-B? Please describe any recommended changes in detail.

LSPGC Response: LSPGC recommends conducting processes in parallel rather than in series. On previous LSPGC projects (Gates and Round Mountain) significant time was taken between the CEQA process and PTC briefing and drafting the proposed decision. These actions were taken in series, with the CEQA process being completed prior to the PTC briefing and drafting the proposed decision. LSPGC recommends that the CPUC allow for these processes to take place in parallel (i.e., when the draft CEQA document is available for public comment) rather than in series, which may allow for efficiencies in full project approval.

d. More broadly, is there an optimal way to sequence the build-out of the grid? Are there workforce or supply chain constraints that prevent projects from being constructed simultaneously?

LSPGC Response: See response to Question 5.

7. In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023, settling parties proposed adding “power line facilities or substations” to the second clause of section III.B.1.g. Of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, how many are located within a “utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies”? Please provide a list of these projects and the applicable utility corridor(s). Of these projects, how many currently qualify for exemption “g”, and how many would qualify for exemption “g” if the settlement agreement suggestion were to be implemented? Do the parties anticipate other, future utility corridors that would impact the use of exemption “g”? Please explain.

LSPGC Response: No Response.

8. Please explain whether the proposals in the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023 are consistent with the following provision of GO 131-D or whether this provision should be amended: “For all issues relating to the siting, design, and construction of electric generating plant or transmission lines as defined in Sections VIII and IX.A herein or electric power lines or substations as defined in Section IX.B herein, the Commission will be the Lead Agency under CEQA, unless a different designation has been negotiated between the Commission and another state agency consistent with CEQA Guidelines § 15051(d).”

LSPGC Response: No Response.

9. How should the ability of non-wire alternatives and distributed energy resources to meet project objectives be evaluated? Should the CPUC still pursue the deferral of distribution upgrades through the use of distributed energy resources? What is CAISO's current process for reporting on the feasibility of non-wire transmission alternatives (and can this process be improved to provide the CPUC with information that better informs the CEQA process)? How are distribution-level non-wire alternatives considered by an applicant prior to application submittal? What opportunities could the CPUC pursue to streamline review of non-wire distribution-level alternatives, and should the CPUC pursue this issue?

    LSPGC Response: Non-wire alternatives (NWA) and distributed energy resources should be evaluated on a CAISO level transmission planning scale, rather than on a CPUC project approval level. The rationale behind this is that projects that are available for competitive solicitation are projects that typically involve, through one way or another, adding capacity or capability to the system in order to meet state policy goals. CAISO has the ability to study or solicit NWA and distributed energy resources through its planning process, but in instances where CAISO selects a transmission or substation project, the project sponsor for the selected transmission or substation project is not at liberty under the terms of its APSA with CAISO to change the project to a NWA or distributed energy resource project. As such, it would not make sense to study such an alternative that would not be implemented as part of a project-specific alternatives analysis during CPUC permitting.

    Regarding the remaining questions that pertain to distribution systems and CAISO's processes for dealing with NWAs, these questions are not within LSPGC's purview; thus, we defer to others for these responses.

10. Please review the generic list of permits required for a typical electric transmission project at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/g/5066-generictransmissionlinepermit.pdf. Should this list be updated? If so, please use the format in the linked table to list all the permits that are required for a typical transmission project (PTC and CPCN) from all federal and State agencies. If there are no "typical" projects, please use at least three projects as examples and list the permits required for each project.

    LSPGC Response: No response.

For non-IOU PTOs and independent transmission developers:

11. Have any independent transmission developers experienced project delays due to actions of incumbent utilities that they were competing against in a CAISO competitive bidding process? Please explain the circumstances and any actions the CPUC could take to streamline utility processes relating to such delays.

    LSPGC Response: There are inherent delays related to how incumbent utilities interact with third parties. However, LSPGC has no instances to report of incumbent utilities losing a competitively selected project to LSPGC then intentionally creating roadblocks to development.

References

California Public Utilities Commission. CPUC. 1995. Public Utilities Commission of the State of California. Online. https://docs.cpuc.ca.gov/PUBLISHED/Graphics/589.PDF. Site visited February 2024.

California Public Utilities Commission. CPUC. 2019. Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments. November 2019, Version 1.0. 91 pages.

March 8, 2024

Via Email

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Subject: Docket No. R.23-05-018, Horizon West Transmission, LLC (U222-E) Response to Data Request 01

Dear Mr. Alexander:

Horizon West Transmission, LLC (U222-E) ("Horizon West") provides the following response to Data Request 01. Horizon West appreciates the opportunity to provide information to Commission Staff in this proceeding and appreciates the Commission's proactive work on the topic.

Horizon West notes that its affiliates, Trans Bay Cable LLC (U934-E) and GridLiance West LLC, do not have information that is responsive to this request.

Horizon West would like to highlight three opportunities for the CPUC as it revises GO 131-D.

(1) **Accept the approval of a project by the CAISO in its Transmission Plan as demonstration of the need for the project and, for competitively bid projects, reasonableness of cost**. The CAISO studies and determines which transmission upgrades are necessary for reliability, policy, and economic purposes in its Transmission Planning Process. The CPUC has extensive input to that process, including the underlying resource mapping and comments through the stakeholder proces. In the case of competitively bid projects, the CAISO consistently uses costs as a key selection factor. Therefore, the CPUC should consider accepting the CAISO's approval of a project as demonstration of need and, in the case of competitive projects, reasonableness of cost.

(2) **Focus resources on the larger projects requiring a Certificate of Public Convenience and Necessity and Environmental Impact Reports.** These projects are critical for California to meet its emissions goals and difficult to replace with other, smaller solutions. They also face some of the most challenging permitting timelines.

(3) **Consider a lower level of detail for the Proponent's Environmental Assessment or foregoing the PEA altogether.** By accepting conceptual routing, design, and desktop analysis of impacts, the CPUC would shorten or eliminate a process that is redundant to the preparation of the CEQA document.

Detailed responses to Data Request 01 are included hereafter. Horizon West thanks the Commission Staff for its efforts and is ready to support in any way possible.

/s/ Tracy C. Davis
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On behalf of Horizon West Transmission, LLC (U222-E)

1. **Please answer the following questions regarding the internal utility planning, design, and application process for electrical transmission projects:**
   a. **On average, how long does it take for a project to be submitted to the CPUC via CPCN or PTC application after it has been approved in a CAISO Transmission Plan? Provide the data used to calculate the average.**

Response: For the two projects for which Horizon West has submitted Certificate of Public Convenience and Necessity ("CPCN") or Permit to Construct ("PTC") applications to the California Public Utilities Commission ("Commission" or "CPUC"), the average time from CAISO Transmission Plan approval to application was 21.5 months. Notably, both of Horizon West's projects resulted from the CAISO's competitive transmission solicitation process (meaning that Horizon West was selected as the Approved Project Sponsor in that competitive process); the average time from competitive project sponsor selection to the filing of Horizon West's CPUC applications was 14.5 months. Please see the respective timelines for each of Horizon West's CPUC applications below. Note that the Estrella Substation and Paso Robles Area Reinforcement Project ("Estrella Project") includes elements that, pursuant to the CAISO tariff, can be built only by the incumbent utility, Pacific Gas and Electric Company ("PG&E"). This feature required Horizon West and PG&E to file a joint application requesting separate PTCs for their respective portions of the Estrella Project. It was more complicated and time consuming to coordinate and prepare the joint application, which partially accounts for the longer lead time between CAISO project award to filing of the CPUC application for the Estrella Project compared with the lead time for the Suncrest Dynamic Reactive Power Support project ("Suncrest Project") that Horizon West filed individually. That lead time for the Estrella Project was 22 months for its PTC application, compared with 7 months for the Suncrest Project's CPCN application.

Suncrest Dynamic Reactive Power Support Project (Suncrest Project), Docket No. A.15-08-027	**Estrella Substation and Paso Robles Area Reinforcement Project (Estrella Project), Docket No. A.17-01-023**
July 2014 – CAISO Board approved Transmission Plan	July 2014 – CAISO Board approved Transmission Plan
January 2015 – Horizon West selected as project sponsor	March 2015 – Horizon West selected as project sponsor
May 2015 – Approved Project Sponsor Agreement ("APSA") completed	July 2015 – APSA completed
August 2015 – Application submitted to the CPUC	January 2017 – Application submitted to the CPUC
7 months from CAISO project award to CPUC application submitted	**22 months from CAISO project award to CPUC application submitted**
13 months from Transmission Plan approval to CPUC application submitted	**30 months from Transmission Plan approval to CPUC application submitted**

b. **Please explain in detail the key time components in your company's internal planning and application process for electric transmission projects. Provide at least three relevant examples from the last ten years that illustrate a representative range of cases (i.e., the middle and tail ends of the range used to calculate the requested average). For each example, discuss the factors that contributed to the duration of each component of the internal planning and application process.**

Response: Horizon West engages in transmission planning efforts in advance of the CAISO Transmission Planning Process and Transmission Plan(s) to anticipate the projects that will result from each annual cycle for a period of approximately three years into the future. Horizon West also engages in preliminary conceptual routing and due diligence, and strategic planning and positioning (*e.g.*, land and right-of-way acquisition) in advance of Transmission Planning Process approval, making adjustments at certain points during the process (*e.g.*, following issuance of a draft Transmission Plan). However, before the CAISO selects an Approved Project Sponsor for any given project and an Approved Project Sponsor Agreement is executed, careful consideration must be given to the prudency of any incurred expenses.

A key component of a PTC or CPCN application is the Proponent's Environmental Assessment ("PEA") required to be submitted to the CPUC with the application. The CPUC publishes detailed instructions on the required content of the PEA. Among other documentation, the PEA must include relatively detailed engineering and construction information and environmental impact analyses. A key component of the latter is having enough environmental resource data, such as data from field surveys, to accurately assess a project's potential impacts. In fact, part of the pre-filing process with the CPUC is reaching agreement with the CPUC on the survey plan and acceptable level of completion for engineering and survey data. Based on the experience of Horizon West, as well as the experience of its consultants and subject matter experts ("SMEs"), the CPUC generally requires a level of engineering similar to a 30% design, plus significant completion of key surveys, such as biological and cultural surveys. To accomplish these tasks, Horizon West must identify contractors, obtain a minimum level of right-of-entry to complete surveys, and progress the iterative and connected processes of engineering design and environmental analysis, the results of which must be documented in the PEA.

There are significant trade-offs between the amount of work done prior to a project award and the length of time that it takes to prepare and file a complete application. Especially with reliability-driven projects, for which the time between approval and the in-service date is supposed to be shorter given the nature of the need for the project, there may not be sufficient time to complete certain pre-application work, especially considering the often-protracted processes for the CPUC's CEQA process and regulatory proceedings. However, for competitive projects it may not be reasonable to complete extensive PEA preparation in advance of the CAISO selecting a project sponsor, as it may involve multiple entitles completing duplicative survey work beyond what is necessary to submit a project proposal that would ultimately go unused by all but the selected project sponsor.

c. **At what percentage of design completeness (e.g., 30% design, 60% design) does your company typically aim to file an application with the CPUC?**

Response: Horizon West aims to file an application with the CPUC at approximately 30% design. While some design details may evolve after submittal of the application, certainty with regard to routing, siting of structures, and construction planning, which all contribute to the locations and nature of the work to be performed, is essential to the environmental impacts analysis in the PEA. Not all details can be known at the time an application is submitted, but the better-defined and studied a project, the greater the probability that the CPUC deems the application complete and that delays can be avoided from significant changes occurring after the application is filed, or, having even greater an impact, after the CEQA review is complete. Horizon West's experience is that filing at approximately 30% design is the appropriate level of completeness to address these factors.

d. **At what point in the project planning and design process does your company engage contractors to support scoping, routing, and preparation of technical studies?**

Response: Please see the response to Question 1(b). Prior to issuance of an RFP by the CAISO, Horizon West will work on early-stage scoping of expected projects. This usually entails internal and external project management, engineering, system planning, and other development support. Once the CAISO releases an RFP, Horizon West will hire an engineer-of-record to support all preliminary design to further improve design, determine procurement requirements, and scoping for project estimating. At approximately 30% design, we will engage various additional contractors to support preliminary route reviews, general feasibility analyses, subsurface reviews, and constructability investigations. This includes engineering, surveying (LiDAR), both internal and external construction support, environmental services, legal, and land services teams.

e. **Please describe any ideas that could accelerate the internal utility planning and application process prior to the submittal of an application to the CPUC.**

Response: One way to accelerate the internal utility planning and application process prior to submittal of an application to the CPUC would be to streamline and shorten the pre-filing process with CPUC Energy Division, including the process to retain Energy Division contractors. In Horizon West's experience, this process can be lengthy and can delay the filing of an application and the start of the environmental review process.

2. **Please answer the following questions regarding application filing and pre-filing review:**
    a. **Once a project is approved by CAISO, should the CPUC require the project proponent to file an application within a specified time window after CAISO approval (e.g., within one year) or within a specified time window prior to the required or forecasted in-service date (e.g., two years prior to the in-service date)? Alternatively, is it feasible to institute different filing deadlines based on project type and complexity? Please explain.**

Response: Horizon West does not believe that requiring proponents to file applications within a specified timeline after the project is approved via the CAISO's Transmission Plan and, for competitive projects, awarded through the CAISO competitive solicitation process, would be feasible or would meaningfully impact the total time from CAISO approval to project in-service date. In Horizon West's and consultants' experience, each transmission project is unique and involves unique requirements, *e.g.*, the size and scope of the project, the number of environmental agencies and local governments that must be consulted, and the length of the resulting consultation processes that must be undertaken. Thus, Horizon West believes it would be difficult to implement a "one-size-fits-all" deadline after project approval or selection within which an application must be filed with the CPUC. By and large, utilities have incentives to submit project applications as quickly as possible, and thus, delay in submitting applications is often driven by situations beyond the utility's control. For example, as shown in the response to Question 1(a), the necessity for filing a joint application for projects involving both competitively awarded components and components that must be built by the incumbent utility can extend the timeline for preparing and filing an application.

Also, while there is much room for improving timelines in the CPUC's process, some projects, such as policy-driven projects, have more comfortable timelines from award to a project sponsor to in-service date. Imposing a deadline on project sponsors would not benefit the process.

Other measures could accelerate the timeline from award of a project to in-service date. For example, at present, even if project sponsors initiate introductory meetings immediately upon award, the time it takes for the CPUC Energy Division to contract with a consultant to receive and review applications creates a protracted pre-filing process and can delay the start of the environmental review process after the application is filed. If the CPUC tracked the CAISO's Transmission Planning Process and preemptively established contracts that could, retroactively, be funded through proponent cost recovery, CPUC consultants could be contracted and already becoming familiar with the projects before the final CAISO Transmission Plan is approved.

In addition, the CPUC and its consultants require a level of detail in the PEA, including a minimum level of engineering design, field survey data, and environmental analysis, to deem an application complete that is difficult to achieve given the timing and the nature of the CAISO's Transmission Planning Process. For example, projects are awarded in approximately April, leaving little time to kick off the project, get contracts in place, and to execute biological field surveys, most of which need to occur in the Spring. The application process would be accelerated if the CPUC accepted a lower level of detail in the PEA, essentially just conceptual routing, design, and desktop (only) analysis of impacts, understanding that additional detail can be provided via revisions later.

Further, allowing project sponsors to forego the PEA process, instead preparing a traditional initial study, working with the CPUC to understand the scope of CEQA review, and then to prepare the CEQA document through the Project Sponsor's consultants, subject to review by the CPUC, would eliminate a redundant process.

Finally, the CEQA process could be further streamlined by imposing statutory timelines on CEQA process steps, and on the formal portion of the proceeding that is conducted before an administrative law judge.

b. **Are there modifications to the pre-filing review process or application process that would incentivize applicants to initiate pre-filing consultation with the CPUC earlier in the project design process? Please explain.**

Response: Horizon West anticipates initiating the pre-filing process as soon as possible and as is relevant upon award of the project (*i.e.*, once the CAISO has identified Horizon West as an Approved Project Sponsor). As noted above, applicants already are incentivized to complete and submit an application as early as possible, but some projects by their nature will allow for a longer lead time from award to in-service date. In those cases, it may be to the benefit of the proponent and CPUC to delay the pre-filing process until project development is progressed. In many cases, the timelines will be shorter. Regardless of the timeline, there is little value in imposing timelines or deadlines for the proponents to initiate pre-filing. As noted under (a) above, the critical path to submitting an application is development of a PEA that is sufficient to allow the application to be deemed complete.

Implementing methods to streamline the CPUC's processes after an application is filed would accelerate the timeline from project award to application filing, and Horizon West believes this should be the focus of reforms. Horizon West's first project, the Suncrest Project, required a CPCN, and the CPCN process before the CPUC required more than three years to complete (from filing of the application for a CPCN in August 2015 to issuance of the CPCN in October 2018). This three-year CPCN process seemed like an extensive amount of time, but Horizon West's second project, the Estrella Project, which requires a PTC rather than a CPCN, has taken far longer. Horizon West filed the PTC application jointly with PG&E in January 2017 and the application is still pending before the CPUC more than seven years later. The extensive amount of elapsed time in the PTC application process has delayed construction of a project that is needed for reliability. Below is a summary of the timing of the Estrella PTC proceeding that illustrates the extensive delays.

Action/Step	Dates and Elapsed Time since Application Filing Date
1. Application for PTCs filed	January 2017
2. CPUC review of PEA, issuance of data requests, environmental and transmission analyses	February 2017 – February 2020 3 years
3. Draft EIR issued	December 2020 Almost 4 years
4. Recirculation of Draft EIR	November 2021 Almost 5 years
5. Final EIR issued	March 2023 More than 6 years
6. Scoping Ruling	August 2023 Approximately 6.5 years
7. Testimony submitted	August and September 2023 Approximately 6.5 years
8. Briefs filed	October 2023 More than 6.5 years
9. Ruling accepting Final EIR and testimony into the record	February 2024 More than 7 years
10. Proposed Decision	Not yet issued

Adopting expected timelines for the CEQA review process and the formal process before administrative law judges could help avoid these extensive delays for future projects.

Close coordination between CPUC and CAISO with regard to the evolution of the Transmission Plan also may improve timelines by ensuring that the CPUC is prepared to facilitate the pre-filing process earlier following project award.

c. **Are there other modifications to GO 131-D that could enable applicants to provide project information (e.g., in-service date, project objective and design, potentially feasible siting/routing) to the CPUC on an expedited basis for CAISO-approved projects, or that could otherwise enable the CPUC to begin environmental review sooner? To what extent can this information be provided prior to application filing via the Transmission Project Review (TPR) Process or via existing recurring meetings between IOUs and CPUC staff? Please explain.**

Response: Horizon West believes that the CPUC should consider deferring to the definition of purpose and need, in-service dates, project objectives, technical specifications, and alternative solutions to those that are adopted in the CAISO Transmission Plan. This will shorten application preparation and review times and may help streamline and shorten the overall application review process. As needed, the CPUC could increase its involvement in the CAISO's Transmission Planning Process.

One example of duplicative work occurred in the Estrella Project CEQA review process when the CPUC hired a consultant to conduct its own transmission analysis and considered many non-wires alternatives to the transmission upgrades approved in the CAISO's Transmission Plan. This required months of work and considerable expense. Time spent by the CPUC in reengineering transmission solutions already vetted and selected in the CAISO's Transmission Plan can cause significant delays.

3. **Please answer the following questions regarding the provision of cost estimates:**
    a. **Please explain in detail the point in your internal planning process at which cost estimates are typically submitted to the CPUC, when required. What actions are required for applicants to provide an estimated cost for PTC projects and a statement of why the project is needed? What challenges or barriers do applicants encounter during this process? Can they be addressed by the Commission, and if so, in what ways can they be addressed?**

Response: Updates to cost estimates require between three and eight weeks. The longest-lead item is quotes on custom materials, followed by detailed construction estimates.

b. **Would showing that a project was selected as a result of a competitive process at the CAISO, which includes a cost cap, satisfy requirements to demonstrate the cost and need for CPCN and PTC projects?**

Response: Yes, the selection and approval of a project by the CAISO in its Transmission Plan, and the selection of an Approved Project Sponsor after a competitive solicitation process should be deemed to satisfy requirements to demonstrate the need for the project and the reasonableness of the project costs.

The CPUC provides fundamental inputs that lead to the CAISO's identification and selection of necessary transmission upgrades in the CAISO's annual transmission planning process. The CPUC provides busbar mapping for new generation and storage resources required to be built to meet California's resource requirements and those mapping results are used in the CAISO's annual transmission planning process to identify transmission facilities needed for reliability, policy, and economic purposes. The CAISO also considers alternate solutions before it approves a project in its Transmission Plan.

Finally, the CAISO has the expertise and information to study and determine which transmission upgrades are necessary for reliability, policy, and economic purposes. Therefore, once a transmission project is selected by the CAISO in its Transmission Plan, that selection should be deemed to satisfy requirements to demonstrate the need for the project in the CPUC's CPCN process. The CPUC should also recognize and incorporate the CAISO's project objectives in the CEQA process, to minimize time required to identify a project's objectives in the ultimate CEQA document.

If the Approved Project Sponsor was selected through a competitive solicitation conducted by the CAISO, then the CPUC should consider that competitive process and any resulting cost containment in determining the reasonableness of the project costs for the CPUC's CPCN process.

c. **To what extent are any delays in the provision of cost estimates attributable to the design and planning of interconnection to the distribution system? Please explain and provide examples.**

Response: Horizon West does not have a specific response to this question.

d. **Please also explain the typical time periods for cost estimates to reach different levels of reliability (e.g., 100% contingency, 50% contingency, 25% contingency), and what factors may impact these time periods.**

Response: Large projects that require Environmental Impact Reports and CPCNs are particularly difficult to estimate with low contingencies. Refreshing cost estimates requires detailed construction mock-ups and multiple vendor quotes for equipment. Cost estimates can fluctuate over time as demand ebbs and flows for labor and equipment. The CPUC should focus its efforts on progressing these projects swiftly through licensing to maintain cost stability throughout the process, which will provide predictability and allow utilities to be more precise in their estimating and the amount of contingency required.

e. **When and why do costs submitted to the CPUC in the application process differ from costs identified in the CAISO Transmission Plan? Please provide a range of examples of such projects and explain what caused the difference.**

Response: Costs submitted to the CPUC in the application process generally reflect a higher level of diligence and design certainty than those provided to the CAISO as part of its competitive solicitation process or the Transmission Planning Process. This can lead costs to differ between the CAISO Transmission Plan and a CPUC application.

Differences may occur, for example, as the project is more fully designed and receives additional public and agency feedback, which may cause modifications or adjustments to the project as originally identified by the CAISO. Differences may also be caused by Uncontrollable Forces, significant changes in project scope, or differing interconnection requirements from interconnecting utilities, just to name a few.

Whether a project went through the CAISO's competitive transmission solicitation process also may impact whether there are differences between costs in the CAISO Transmission Plan and costs presented in a CPUC application. For entities that include firm cost containment provisions in their bids to CAISO and their Approved Project Sponsor Agreements, the costs may not differ significantly from those proposed to the CPUC (subject to any changes due to Uncontrollable Forces or significant changes in project scope, for example). As described above, the CPUC should factor the CAISO's competitive process and any resulting cost containment commitments into its evaluation of the reasonableness of a project's costs in CPCN proceedings.

4. **Please answer the following questions regarding the CPCN and PTC exemption criteria:**
   a. **Would adding specificity to the CPCN and PTC exemption criteria (e.g., including a non-exhaustive list of examples of "equivalent facilities or structures", "minor relocation", and "accessories") increase applicant certainty regarding whether an exemption would apply and/or increase the number of projects for which an exemption may apply? If so, please provide specific suggestions (e.g., converting existing lattice towers or wood poles to steel monopoles no more than X percent taller than the existing structures). If additional terms are proposed, please provide definitions.**

Response: Horizon West does not have a specific response to this question.

   b. **Would adding specificity to the term "minor relocation of existing power line facilities" in Section III.A (for CPCN exemptions) increase advice letter filings and reduce application filings (e.g., by increasing the number of projects that are eligible for PTC exemptions 1b, 1c, and 1e)? Please explain.**

Response: Horizon West does not have a specific response to this question.

   c. **Would reformatting the CPCN exemptions in GO 131-D Section III.A as an ordered list, similar to the existing list of PTC exemptions in Section III.B.1, increase applicant certainty regarding whether an exemption would apply?**

   Response: Horizon West does not have a specific response to this question.

   d. **Are there any other pros and cons to making such modifications? Please explain.**

   Response: Horizon West does not have a specific response to this question.

5. **What are the current typical lead times for obtaining equipment critically necessary to complete transmission projects (such as transformers, circuit breakers, busbars, conductors, etc.)? What factors influence the calculation of estimated lead times? Are there any emerging issues (e.g., supply chain) that will significantly impact future lead times? What actions can transmission developers take to expedite timelines for obtaining equipment? Could explicit authorization to procure long-lead-time equipment expedite transmission projects?**

   Response: Lead times vary depending on system demand at the manufacturing facilities and the available capacity to produce. Aging infrastructure has led many utilities to begin major replacement programs. The significant increase in renewable energy plants that require substations and transmission lines has also increased the need for more products that will compete with existing utilities. Transformers and high voltage circuit breakers have seen the largest jump in lead times, currently exceeding two years.

6. **Of all the transmission projects approved by CAISO in the past five years, is there a subset of projects that should be prioritized (e.g., policy-driven transmission projects) for California to reach its emission reduction goals? Please explain.**

   Large, complex projects that require EIRs and CPCNs are critical for California to meet its emissions goals and difficult to replace with other, smaller solutions. Projects such as Imperial Valley – North of SONGS 500 kV Project move large amounts of power from renewable sources to load. These larger projects are hard to replace with incremental improvements (e.g., local storage, behind-the-meter, or energy efficiency). They have long lead times and high variability. Finally they contribute an outsized amount of the cost of reaching emission reduction goals. The CPUC should therefore focus its efforts to ensure these large, complex projects requiring EIRs and CPCNs are prioritized and sequenced first.

   a. **Would prioritizing these projects help streamline permitting? If so, can this be accomplished by changes to GO 131-D in Phase 2 of this proceeding?**

   Response: Horizon West believes prioritizing these projects would help streamline permitting.

   b. **To what extent could more detailed project routing and siting work coupled with feasibility studies and high-level environmental constraint analyses conducted up front during the CAISO transmission project identification and planning processes streamline subsequent State siting approvals?**

   Response: Attempting to conduct more detailed routing and siting work during the CAISO process may not ultimately increase the efficiency of transmission solution permitting and deployment.

c. **Are there other changes to the electric transmission planning and permitting process that would be necessary to achieve State emission reduction goals, e.g., new legislation or changes to GO 96-B? Please describe any recommended changes in detail.**

Response: Horizon West does not have a specific response to this question.

d. **More broadly, is there an optimal way to sequence the build-out of the grid? Are there workforce or supply chain constraints that prevent projects from being constructed simultaneously?**

Response: As described in the response to question 6, large, complex projects that require CPCN's and EIR's are hard to replace with smaller incremental improvements. The CPUC should consider dedicating additional resources to the large projects identified by the CAISO which require EIRs and CPCNs.

7. **In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023, settling parties proposed adding "power line facilities or substations" to the second clause of section III.B.1.g. Of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, how many are located within a "utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies"? Please provide a list of these projects and the applicable utility corridor(s). Of these projects, how many currently qualify for exemption "g", and how many would qualify for exemption "g" if the settlement agreement suggestion were to be implemented? Do the parties anticipate other, future utility corridors that would impact the use of exemption "g"? Please explain.**

Response: Horizon West supports the inclusion of "power line facilities and substations" in the second clause of section II.B.1.g. Any such modification should clarify that only a portion of the line need be included in such a corridor to qualify. For example, Horizon West submitted proposals for multiple projects identified by the 2022-23 CAISO Transmission Plan proposing routes within a BLM368 corridor, including:

- North Gila – Imperial Valley (>80%) – should qualify
- Imperial Valley – North of SONGS (~20%) – unlikely to qualify

8. **Please explain whether the proposals in the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023 are consistent with the following provision of GO 131-D or whether this provision should be amended: "For all issues relating to the siting, design, and construction of electric generating plant or transmission lines as defined in Sections VIII and IX.A herein or electric power lines or substations as defined in Section IX.B herein, the Commission will be the Lead Agency under CEQA, unless a different designation has been negotiated between the Commission and another state agency consistent with CEQA Guidelines § 15051(d)."**

   Response: Horizon West does not have a specific answer to this question.

9. **How should the ability of non-wire alternatives and distributed energy resources to meet project objectives be evaluated? Should the CPUC still pursue the deferral of distribution upgrades through the use of distributed energy resources? What is CAISO's current process for reporting on the feasibility of non-wire transmission alternatives (and can this process be improved to provide the CPUC with information that better informs the CEQA process)? How are distribution-level non-wire alternatives considered by an applicant prior to application submittal? What opportunities could the CPUC pursue to streamline review of non-wire distribution-level alternatives, and should the CPUC pursue this issue?**

   Response: The CPUC should recognize and incorporate the purpose and need for projects, as well as technical alternatives analysis, as vetted through the CAISO Transmission Planning Process in its CPCN. As discussed above, the CAISO considers alternate solutions as part of its Transmission Planning Process before it approves a project in its Approved Transmission Plan and selects an Approved Project Sponsor. The CPUC can and does participate in the CAISO's process. Therefore, consideration of alternatives in the CPUC process is often duplicative and time-consuming.

   For example, in the CPUC's consideration of the Estrella Substation Project, substantial time was spent evaluating whether battery storage facilities were an alternative to the substation project that was identified and selected by the CAISO in its Transmission Plan. This study of alternatives that would not meet the CAISO's identified need added considerable time and expense to the PTC process.

10. **Please review the generic list of permits required for a typical electric transmission project at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/g/5066-generictransmissionlinepermit.pdf. Should this list be updated? If so, please use the format in the linked table to list all the permits that are required for a typical transmission project (PTC and CPCN) from all federal and State agencies. If there are no "typical" projects, please use at least three projects as examples and list the permits required for each project.**

    Response: Horizon West does not have a specific answer to this question.

For non-IOU PTOs and independent transmission developers:

11. **Have any independent transmission developers experienced project delays due to actions of incumbent utilities that they were competing against in a CAISO competitive bidding process? Please explain the circumstances and any actions the CPUC could take to streamline utility processes relating to such delays.**

    Response: The need to coordinate with interconnecting incumbent utilities can lead to project delays in a number of ways.

    In general, the process for large projects requires coordination amongst multiple groups, including a selected project sponsor and interconnecting incumbent utilities. Interconnection with incumbent utilities is a key component of identifying the scope analyzed and submitted to the CPUC. Statutory timeline requirements for key steps of the CEQA and CPCN process could help provide the certainty needed to plan for these projects and help create incentives to complete the necessary interconnection processes more quickly.

    In addition, as noted above in Question 1(a), where projects awarded by the CAISO through the competitive solicitation process contain competitive and non-competitive components, the time required to coordinate a joint filing or coordinated filings can add time and complexity in preparing and the CPUC's processing of an application.

    Delays can also occur where an incumbent interconnecting utility imposes unforeseen interconnection requirements on a competitive project (*e.g.*, requirements to underground certain interconnection facilities that were not originally identified as required through the CAISO solicitation process) or intervenes in an independent transmission developer's CPUC proceeding to contest aspects of the project as selected by the CAISO. These types of issues are better addressed and resolved in the CAISO's Transmission Planning Process, as the CAISO is identifying projects for which it will solicit competitive bids and the interconnection requirements for those projects, rather than through the CPUC's CPCN or PTC process, which can lead to delays in the project's ultimate in-service date.

CPUC DATA REQUEST
CPUC-SDGE-GO131-001
SDG&E RESPONSE

Date Received: January 29, 2024
Date Submitted: March 8, 2024

QUESTION 1

Please answer the following questions regarding the internal utility planning, design, and application process for electrical transmission projects:

a. On average, how long does it take for a project to be submitted to the CPUC via CPCN or PTC application after it has been approved in a CAISO Transmission Plan? Provide the data used to calculate the average.
b. Please explain in detail the key time components in your company's internal planning and application process for electric transmission projects. Provide at least three relevant examples from the last ten years that illustrate a representative range of cases (i.e., the middle and tail ends of the range used to calculate the requested average). For each example, discuss the factors that contributed to the duration of each component of the internal planning and application process.
c. At what percentage of design completeness (e.g., 30% design, 60% design) does your company typically aim to file an application with the CPUC?
d. At what point in the project planning and design process does your company engage contractors to support scoping, routing, and preparation of technical studies?
e. Please describe any ideas that could accelerate the internal utility planning and application process prior to the submittal of an application to the CPUC.

SDG&E RESPONSE 1a

Other than an arbitrary mathematical calculation, SDG&E does not believe that there is an "average" time to prepare a CPCN or PTC application for a project approved in a CAISO Transmission Plan because the time required is dependent upon factors specific to the project. In SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-001 (submitted November 21, 2023, Revision 1), Question 1A, SDG&E explained why one electric project approved in a CAISO Transmission Plan may take longer to result in a CPUC application than another electric project approved in a CAISO Transmission Plan, assuming that both projects require CPUC pre-authorization under GO 131-D. SDG&E attaches hereto as Attachment 1 and incorporates herein the entirety of its revised response to CPUC Data Request CPUC-SDGE-TPP-001, Question 1A. For Energy Division's convenience, SDG&E sets forth the overview from that response here:

> At a high level, there are several factors that may impact the time it takes to develop a project from CAISO Transmission Plan approval to any required CPUC application.

First, as discussed in response to Question 5, SDG&E allocates its available resources based upon a prioritization of needed projects. TPP projects are prioritized the same as all the other capital projects in the company portfolio. Projects are categorized into one of four project drivers; (1) Safety; (2) Federal/State Commitment; (3) Customer Driven; and (4) Reliability. Safety projects encompass SDG&E's wildfire mitigation, compliance requirements, and other enterprise risk reduction projects. Federal/State Commitment projects encompass CAISO planning (i.e. TPP projects), CPUC (Non-GRC) commitments (projects such as Clean Transportation, DDOR, customer generation interconnects, etc.), and non-safety compliance. Customer Driven projects include new business, franchise, and conversions/relocations. Reliability encompasses aging infrastructure, non-CAISO reliability/capacity, operational enhancements, generation, and sustainability.

Several other criteria also are taken into consideration for overall project prioritization. The next level of prioritization is budget and schedule where funding, total budget, and current project status are considered. For example, a project in construction will take a higher priority over a project in preliminary design. We also prioritize projects based on complexity and risk. This level considers the permitting requirements, execution risk, asset types affected, and potential impacts. Larger scale projects that have a higher execution risk or encompass transmission, substation and distribution facilities will typically be prioritized higher. In addition, projects are identified by the CAISO as needed by a certain date due to the load forecast that is used to develop the model used by the CAISO. Over time, the load forecast can change, and the need for that project can also change due to increases or decreases in the load forecast. Significantly, the widespread deployment of rooftop solar reduced the load forecast for several years, affecting the need for several transmission projects, delaying the in-service dates. However, since 2016, adjustments have been made to CEC modeling to more fully account for DR resources.

Second, the time it takes to develop a project may be significantly impacted by the project itself. Projects have different characteristics, including but not limited length of any transmission or power line, location, number of circuits, voltage, required supporting structures, potential environmental impacts, third party stakeholders, land acquisition issues, public outreach, and local jurisdiction interactions. For example, generally it takes longer to engineer and perform environmental review of a 50-mile transmission line than a 10-mile transmission line, it takes longer to engineer construction of a new line than to reconductor an existing line, and it takes longer (usually) to engineer a new substation than to add a piece of equipment to an existing substation. Environmental review of construction in franchise in an urban area usually takes less time that environmental review of a new facility in "greenfields." Timelines can vary greatly project to project depending on environmental conditions, field conditions, permitting needs (CPUC, local, federal/NEPA, Coastal Commission, etc.), amount of field visits and geotech work needed, the impacted landowners (e.g. a project on Camp Pendleton takes additional time not only for permitting but because the military is slow to respond). It all is dependent on the particular characteristics of each individual project.

Third, because each project must be designed individually, its development often is iterative, requiring changes to design as routing or the nature of construction changes. Vetting a physical route or location for projects often takes significant time, based on the complexity and location of the project. The project team (including representatives from Project Management, Engineering, Land, Regulatory, Public Affairs, Construction, and Environmental) work iteratively on designs and land needs to reduce environmental impacts while also meeting the CAISO Transmission Plan (or SDG&E for non-CAISO projects) technical requirements. Determining the alignment can take multiple field visits to analyze environmental/engineering/access constraints and constructability. In between visits, time is needed to adjust the design to address any problems found. Geotech and survey work also takes a significant amount of time – crews have to be scheduled, permits and license agreements may be required (especially on military land), and time is needed to not only collect the data but process it.

Fourth, the time between CAISO approval and any CPUC filing may be shortened if SDG&E has undertaken more engineering and environmental review before CAISO approval. For example, SDG&E's CPCN application for the SOCRE project was submitted a year after CAISO approval because much of the engineering and environmental impact analysis was completed prior to the CAISO approval. This approach is not typical for most projects because of the risk that CAISO will not approve a project. SDG&E proceeded with the SOCRE work at risk because our analysis showed the potential for a large impact on our system if the project was not prioritized and fast tracked. Given the risk to cost recovery, such work will be uncommon.

Fifth, some projects have limited environmental impacts or impacts can be mitigated through design changes, and/or a CPUC permit is not required under GO 131-D. For those projects that do require CPUC permitting, the project team's goal is to submit an application that ED agrees is complete and where impacts are methodically addressed with effective proposed mitigation measures to allow efficient construction of the project. The time it takes to prepare an application, including a Proponent's

Environmental Assessment (PEA), meeting the CPUC's requirements is driven by the CPUC's requirements, including the PEA Guidelines.

Because the time it takes to prepare a CPUC application for a CAISO-approved project depends upon factors specific to the project, an "average" time that preparation of a CPUC application for a future project will take cannot be reasonably estimated until such factors are known and addressed. Attempts to calculate an "average" by compiling the time taken to prepare a CPUC application for past projects and dividing by the number of projects in each permitting category would create the false impression that applications for future projects, which may be different in each of the respects noted above, could or would be completed within a particular time frame.

Moreover, SDG&E has limited data from which even a mathematical "average" could be calculated as SDG&E has two CPCN permitted TPP projects and 4 PTC permitted TPP projects going back to 2010.

For one of the two CPCN projects (SOCRE), the CPCN application was submitted in May 2012 after a CAISO Transmission plan approval in the 2010/2011 TPP cycle for a total of 13 months difference. Please note that initiation of this CPCN project occurred years before receiving approval from CAISO, with internal discussions as early as 2002, and included completing a significant portion of preliminary designs and the PEA before CAISO approval. The Commission approved the SOCRE project in December 2016 in Decision 16-12-064, roughly 4 years and 7 months after the application was filed.

For the other CPCN project (Sycamore to Penasquitos), the CPUC application was submitted in April 2014 after a CAISO Transmission Plan approval in the 2012/2013 TPP cycle for an approximate 12 months difference. This project was a FERC 1000 bid project that SDGE won with much of the proposed design completed to meet the requirements of the bid, thus allowing SDG&E to submit an application earlier than a traditional project. The Commission approved the SXPQ project in October 2016 in Decision 16-10-005, roughly 2 years, 6 months after the application was filed.

The times between CAISO TPP Approval and submittal of PTC applications for SDG&E projects subject to a PTC requirement since 2010 are set forth below. SDG&E notes that, although CPUC Rule 2.4 required SDG&E to submit a PEA for all four of the PTC projects in the table below, the CPUC ultimately adopted an IS/MND for each such project. As discussed in response to Question 1.e below, preparing a PEA consistent with the CPUC's PEA Guidelines is inefficient for projects that qualify for an IS/MND. If the CPUC adopts the Settlement Agreement proposed in R.23-05-018, it would expedite the filing of any required CPUC application by allowing the applicant to prepare and submit a draft IS/MND rather than a PEA. See Joint Motion for Adoption of Phase 1 Settlement Agreement, filed September 29, 2023.

Project	Application Type	TPP Approval Date	Permit Application Submittal Date	# Months from CAISO Approval to Filing
Southern Orange County Reliability Upgrade Project – Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	CPCN	2010/2011 (April 2011)	May 2012	13
Sycamore to Penasquitos New 230kV Transmission Line (FERC 1000 Bid Project)	CPCN	2012/2013 (March 2013)	April 2014	13
TL695B Japanese Mesa-Talega Tap Reconductor	PTC	2011/2012 (March 2012)	April 2016	49
TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	PTC	2012/2013 (March 2013)	June 2017	51
2nd Escondido-San Marcos 69 kV T/L	PTC	2013/2014 (July 2014)	November 2017	40
Artesian 230 kV Sub & loop-in TL23051	PTC	2013/2014 (July 2014)	August 2016	25

<u>SDG&E RESPONSE 1b</u>

SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-001, Question 1A, attached hereto as Attachment 1 and incorporated herein by reference, provides a more detailed description of Project Design Steps and Considerations, Land tasks, and Environmental/PEA Preparation. These tasks do not proceed in isolation, but rather the teams responsible for these tasks must coordinate and adjust based upon considerations in each area. Thus, as set forth in SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-001, Question 1A:

> Question 1.A asks SDG&E to "Explain why projects file quickly or slowly." As explained above, projects have different characteristics, including but not limited length of any transmission or power line, location, number of circuits, voltage, required supporting structures, potential environmental impacts, land acquisition issues, public outreach, and local jurisdiction interactions. Timelines can vary greatly project to project depending on environmental conditions, field conditions, permitting needs, amount of field visits and geotech work needed, the impacted landowners (e.g. a project on Camp Pendleton takes additional time not only for permitting but because the military is slow to respond). How long it takes to complete the environmental review tasks, and PEA preparation, is dependent on the particular characteristics of each individual project.
>
> All projects requiring a PEA, however, require a significant level of effort and thus time. As discussed above, SDG&E's environmental assessment proceeds iteratively with the SDG&E project team's evaluation of potential routing of a transmission line (location of a substation) and siting of civil infrastructure (grading, foundations, roads, walls, drainage, etc.). Where potentially significant impacts are identified early in the process, the routing or siting may be changed before many of the detailed PEA assessments are performed. Generally, however, where a PEA must be submitted, SDG&E undertakes the tasks set forth below. Roughly, these follow the PEA format dictated by the PEA Guidelines at 7-8.

SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-001, Question 1A, provides as an example the impact of required biological surveys on the time it takes to prepare an application:

> Required biological surveys can have a significant impact on the time it takes to complete a PEA. For most protected species (species that have some level of protection under either or both of the California or Federal Endangered Species Acts), the wildlife agencies (CDFW or USFWS) will develop "protocols" for focused species-specific surveys that determine the presence or absence of a particular species. Species observation records/databases (e.g., CNDDB) and project-specific general biological resource surveys

and habitat assessments will determine what specific species may require additional (focused) surveys.

The agencies' Protocol will dictate how and when surveys must occur. Where protocols do not exist for a particular species, generally timeframes are used based on accepted/published species information (e.g., blooming period for plants). Presence or absence of a particular species is required to determine a project's impact on said species, and is also needed to determine if a permit (e.g., Incidental Take Permit for ESA protected species) is required. CEQA requires impacts from a project to be disclosed. Surveys that do not follow established protocols run the risk of the lead agency (i.e., CPUC) and/or the wildlife agencies not accepting the survey results. If for some reason focused surveys could not be conducted (maybe a land rights or safety issue), the CEQA document (or PEA) could assume presence of the species in question, then conclude impacts and require mitigation accordingly.

The Protocol's identification of when surveys must be conducted may significantly impact timing. For example, the Survey Protocol for the coastal California gnatcatcher, prepared by U.S. Fish & Wildlife Service, requires that: "Coastal California gnatcatcher surveys shall be completed by permitted biologists if proposed projects are located within the historic range of this species and contain sage scrub plant communities …." Survey Protocol for Coastal California Gnatcatcher (fws.gov) If surveys are required, then, for jurisdictions participating in the NCCP process, a minimum of three surveys are required, preferably between February 15 and August 30, because "loss of coastal sage scrub requires mitigation on a habitat basis, regardless of whether habitat is occupied by coastal California gnatcatchers." For jurisdictions outside the NCCP process: "From March 15 through June 30, a minimum of six (6) surveys shall be conducted at least one week apart. The protocol for the breeding season was designed to provide a 95% confidence level of detecting coastal California gnatcatchers at a site when they are present," or "From July 1 through March 14, a minimum of **nine (9)** surveys shall be conducted at least two weeks apart."

The California gnatcatcher is simply one of many potential species that may be impacted. There can be projects that require surveys for plant, wildlife or bird species at different times of the year, and thus spread the survey process throughout a year. The CAISO Transmission Plans tend to be approved in May. At that point, considerable design work must occur to identify likely survey areas, pushing surveys into the following year. As always, what needs to be surveyed, and when, will be determined by the characteristics of each project, including its routing or location, and lineal extent. That significantly impacts the time to prepare the biological resources impact assessment, and thus how long it may take to prepare the assessment after CAISO approval of a TPP project.

While the time it takes to prepare a CPCN or PTC application is determined by the factors set forth above and in Attachment 1, additionally SDG&E sets forth below the key time components in its internal planning and application process for electric transmission projects as shown by the attached "Template_Permitting & Regulatory Schedule_02-13-24", which is presented as a hypothetical project starting on January 3, 2023 with length of tasks calculated in business days. As this is a template, it includes all the regulatory options (Exempt, Advice Letter, Advice Letter 851, PTC and CPCN). For this template, the overall schedule is based on the longest task items regardless of type of filing. Actual schedules are refined once a regulatory path is determined (i.e. if the project is determined to be an Advice Letter, the other regulatory options will be removed from the schedule and all the associated (predecessor and successor) tasks will be tied to an Advice Letter filing).

Also, attached are 3 project schedules showing actual completions for tasks associated with regulatory approvals and permitting; TL695B Japanese Mesa-Talega Tap Reconductor (please note this project is part of the TL695-6971 - Reconductor (CPEN) Talega to Japanese Mesa project, which is also a fire hardening project), TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap), and 2nd Escondido-San Marcos 69 kV T/L (TL6975).

SDG&E RESPONSE 1c

We conduct preliminary environmental and regulatory review early in the engineering initial cost estimate phase, which can include desktop analysis of environmental resources, focused on biological resources, cultural resources, aquatic resources and impacts to agency lands to develop an initial estimation of the environmental and regulatory pathway that is anticipated to be most likely. This is done for SDG&E initiated and CAISO TPP projects, based on transmission planning studies.

After transmission and substation projects are approved internally and by the CAISO, SDG&E evaluates which projects would likely trigger an Advice Letter, PTC or CPCN, though the final conclusion isn't reached until SDG&E has a more complete design, typically between 30% and 60%. At 30% to 60% design, SDG&E typically already has a consultant on board to assist in preparing the PEA, which will also include the preparation of supporting technical studies such as biological technical reports, cultural and historic resources studies, etc. Our internal Key Performance Indicator to complete environmental analysis and assessment is 60% design, preferably after 30% design job walk. As stated in Response 1b above, while ideally 60% design would have sufficient detail to fully assess construction impacts, there are many unknowns that can impact the attainment of that design that are out of control of the utility.

In any case, for CPUC CPCN or PTC applications, SDG&E typically uses the 60% milestone for overhead facilities and 30% for underground facilities, which are largely located within franchise roadways or utility-owned properties and typically do not have the same level of impact as overhead facilities, particularly biological resources and aesthetics. 30% underground design includes a horizontal alignment but may not have the vertical component fully identified.

SDG&E RESPONSE 1d

SDG&E brings in outside consultants when necessary and the timing varies by project. Typically, more complex projects necessitate bringing on additional outside support and expertise early. These projects are discussed below.

For projects that are upgrades of existing facilities, located within existing ROW, easements or franchise, routing or siting are not as much of a concern, and for most of our projects, this is the case. As stated previously, for these projects the 30% to 60% design phase is the trigger. We may bring on a consultant prior to 30% design if we know an additional internal environmental review is required to confirm whether a project is CEQA categorically exempt or in support of an Advice Letter filing. This also holds for utility relocations but, in these cases, we use internal expertise to work with the relocation initiator's environmental document preparer to ensure that the document can support a PTC exemption (usually under GO131-D III.B.1,f.).

For the less frequent large-scale transmission projects, we still complete our cost estimating and preliminary environmental and regulatory review internally, but will engage with outside engineering support after internal, and CAISO approval, if and as needed. Environmental support consultants typically follow the hiring of the engineering design support, including civil/site development, and is done between 10% to 30% engineering. If the project involves a FERC 1000 bid process, then external resources and expertise are brought on much earlier once we know the CAISO's bid submittal and review process.

<u>SDG&E RESPONSE 1e</u>

First, SDG&E notes that CPUC adoption of the Settlement Agreement proposed in R.23-05-018 would expedite the filing of any required CPUC application. See Joint Motion for Adoption of Phase 1 Settlement Agreement, filed September 29, 2023. SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-001, Question 6, attached as Attachment 1 and incorporated herein by reference, addressed this issue. For Energy Division's convenience, SDG&E repeats its response here (footnote omitted):

> SDG&E appreciates ED's interest in this issue, and is willing discuss with ED any of the ideas set forth below. For any project that requires a CPCN or PTC under GO 131-D, GO 131-D currently requires SDG&E to submit an application that includes a PEA under CPUC Rule 2.4. SDG&E also recognizes that any project requiring a CPUC CPCN or PTC may undergo CEQA review. Therefore, the environmental review must comply with CEQA (and potentially NEPA if applicable). Similarly, to construct the project if approved, SDG&E will need to complete final engineering, prepare construction drawings, contract for labor and materials, and more. Some time-consuming aspects, such as obtaining necessary feedback or approvals from key agencies (including BLM, CNF, BIA, military bases, state parks, and national parks), are beyond the control of either SDG&E or ED. Therefore, in seeking to shorten the time from CAISO approval to CPUC filing (assuming not exempt and no change in priority), SDG&E focused on (1) where the PEA Guideline and/or ED requirements exceed what is necessary to comply with CEQA and (2) where the level of detail required by the PEA Guidelines and/or ED exceed what is needed to evaluate and compare the proposed project and alternatives.
>
> The Guidelines explain that ED will provide feedback on a range of reasonable alternatives to the project for the applicant to study, and "Applicants will ensure that each alternative is described and evaluated in the PEA with an equal level of detail as the proposed project unless otherwise instructed in writing by CEQA Unit Staff." The Commission's Guidelines require the applicant to prepare a PEA that includes the information found in a draft Environmental Impact Report (EIR) for the proposed project.
>
> First, SDG&E notes that CPUC adoption of the Settlement Agreement proposed in R.23-05-018 would expedite the filing of any required CPUC application. See Joint Motion for Adoption of Phase 1 Settlement Agreement, filed September 29, 2023. The proposed revisions to GO 131-D, Section IX.A.1.h, IX.B.1.e, and IX.C provide that, in lieu of a PEA, an applicant may prepare and submit with its CPUC Application "a draft environmental

impact report, draft mitigated negative declaration, draft negative declaration, draft addendum, or analysis of the applicability of an exemption from CEQA (each a CEQA Document)." The ED may continue to "provide the applicant with appropriate guidance and assist in the preparation of the draft CEQA Document. Before using a draft CEQA Document prepared by the applicant, the Commission shall subject the draft to its independent review and analysis. Any draft CEQA Document sent out for public review shall reflect the independent judgment of the Commission." This not only would reduce the post-CPUC filing time for ED to review the PEA and prepare its own CEQA Document, but it would shorten the pre-CPUC filing time by eliminating PEA requirements in excess of what is required by CEQA.

The Settlement Agreement also proposes including "the underlying purpose and project benefits of the proposed project as stated in the relevant CAISO Transmission Plan," albeit without limiting ED's ability to add to such information in its review of an applicant-submitted draft CEQA Document. See Joint Motion, Attachment 1 (Attachment A, Section IX.C.2(a)). The Settlement Agreement provides that the range of reasonable alternatives, if any, in "an initial draft CEQA Document for the proposed project circulated for public comment, shall be limited to alternative routes or locations for construction of the relevant CAISO Transmission Plan-approved electric project." See Joint Motion, Attachment 1 (Attachment A, Section IX.C.2(b)). Both of these provisions would streamline preparation of a draft CEQA Document and thus expedite any required CPUC filing. As noted in response to Question 1.A, both the Commission's IRP process and the CAISO's TPP process consider non-wires alternatives to transmission projects; as a result, a "reasonable range of alternatives" to the routing or location of the CAISO approved project is easily within the applicable rule of reason.

Second, whether by revision to the PEA Guidelines or allowing SDG&E to submit a draft CEQA Document, an applicant should be allowed to proceed with an Initial Study pursuant to CEQA Guideline § 15063 to determine if the project may have a significant effect on the environment, where the applicant believes it is likely that the project may qualify for a Negative Declaration (ND) or Mitigated Negative Declaration (MND). CEQA Guideline § 15063(a)(3) is clear that "an initial study is neither intended nor required to include the level of detail included in an EIR." If an MND is appropriate, then evaluating a reasonable range of alternatives is not required. The PEA Guidelines at 2 provide: "PEAs will be drafted with the assumption that an Environmental Impact Report (EIR) will be prepared. Applicants will include a reasonable range of alternatives in the PEA (even though a Mitigated Negative Declaration [MND] may ultimately be prepared), including sufficient information about each alternative." While the PEA Guidelines indicate that ED may agree that an MND is likely, in practice ED is not willing to agree until it has reviewed a complete PEA, for which all of the detailed analysis, including analysis of alternatives, is required.

For projects ultimately found appropriate for an MND, the current requirements add significant unnecessary time and expense, in evaluating both the proposed project and alternatives. For example, Protocol surveys are driven by the appropriate season and can cause delays of a year or more depending on timing of project initiation or approval by the authorizing entity. For a PEA, completing protocol surveys requires about nine months from start to finish (January to September), not considering certain sensitive or T&E plant species that bloom in the fall. Habitat Assessments based on desktop analysis and fielding allows for a quantification of potential biological resource impacts that are adequate to make a reasonable determination of significance based on conservative assumptions of presence or likelihood of occurrence. ED should establish a threshold for an MND versus an EIR early based on screening questions and the CEQA Initial Study Checklist, and agree to the appropriate level of analysis early during pre-application meetings.

Third, ED should align the PEA Guidelines with CEQA's requirements for evaluating alternatives. CEQA provides: "The EIR shall include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project. A matrix displaying the major characteristics and significant environmental effects of each alternative may be used to summarize the comparison. If an alternative would cause one or more significant effects in addition to those that would be caused by the project as proposed, the significant effects of the alternative shall be discussed, but in less detail than the significant effects of the project as proposed." CEQA Guidelines § 15126.6(d). The PEA Guidelines at 2, however, provide: "Applicants will ensure that each alternative is described and evaluated in the PEA with an equal level of detail as the proposed project unless otherwise instructed in writing by CEQA Unit Staff." The point is to allow a meaningful <u>comparison</u> of the proposed project to an alternative; the PEA Guidelines, however, require much more. This requirement imposes significant unnecessary time and expense.

Fourth, the PEA Guidelines at 40 n. 20 require SDG&E to identify and discuss alternatives that include: "Reduced footprint alternatives; siting alternatives; renewable, energy conservation, energy efficiency, demand response, distributed energy resources, and energy storage alternatives; and non-wires alternatives (electric projects only) are typically required." As discussed in the November 14, 2023 Joint Reply Comments on

Joint Motion for Adoption of Phase 1 Settlement Agreement, R.23-05-018, at 23-28, this requirement forces SDG&E to duplicate analyses previously performed by the CPUC and CAISO in the Transmission Planning Process. The CAISO TPP analysis is based upon the Commission's Integrated Resource Planning ("IRP") resource portfolio, in which the Commission considers energy efficiency, demand-side programs and distributed energy resources ("DERs"). CAISO then evaluates the availability of such preferred resources to solve identified transmission system constraints. The consideration of such non-transmission alternatives is required by CAISO's FERC tariff. The PEA Guidelines could be revised to focus on alternative routing and siting of the CAISO-approved electrical solution.

Fifth, when new routing or siting alternatives are proposed late in the process, sometimes even after a CPUC filing, it requires significant additional engineering time and environmental assessment. Depending upon Protocols for evaluating the presence of particular wildlife and plant species, which specify the time of year when surveys may be taken, the late addition of an alternative can delay PEA completion (or the CPUC's EIR completion if raised post-CPUC filing) for a year. SDG&E suggests that ED provide feedback on desired routing and siting alternatives early and not add more such alternatives later absent specific reason to believe that the newly identified alternative has fewer significant impacts than the proposed project and previously identified alternatives.

Sixth, assessment of biological resources is time-consuming and expensive. The PEA Guidelines, Attachment 2 request that SDG&E massively expand the required survey area beyond that required by CEQA by stating: "The biological survey area should include a 1,000-foot buffer from project facilities to support CPUC's evaluation of indirect effects." This would expand the evaluation to areas with no conceivable impact from proposed facilities, e.g., up to 1000 feet from a transmission line far above the ground, a structure installed by helicopter, a line being installed in a roadway franchise.

Seventh, the PEA Guidelines require an extremely detailed project description through 25 pages of specific instructions. CEQA Guideline § 15124 provides: "The description of the project shall contain the following information but <u>should not supply extensive detail</u> beyond that needed for evaluation and review of the environmental impact." (Emphasis added). SDG&E recognizes that a reasonable amount of detail is needed to evaluate and review the project's potential impacts on environmental resources. However, in some cases, reasonable worst-case estimates or assumptions (about pieces of equipment, numbers of workers, VMT, etc.) should be sufficient to assess potential impact. If there is no significant impact using such assumptions, that is sufficient. If there is a significant impact using such assumptions, SDG&E can either engineer to greater detail or accept that there is a significant impact and alternatives will be considered that may feasibly reduce that impact. Similarly, meaningful comparison of alternatives can be based on similar levels of engineering using similar estimates or assumptions. If ED is interested in exploring a reduction in the level of detail required for the project description, SDG&E is happy to engage in that discussion.

SDG&E notes that the proposed project is not "stable," i.e., certain, until after CPUC review. Based upon the CPUC's CEQA review, and consideration of alternatives and mitigation measures, the project may change significantly. Even when a proposed project uses existing easements and ROW, the CPUC can and will consider completely different routes and configurations. Significant costs and project delays are built into the PEA process by doing more detailed design and environmental assessment than required, and then having to redo it for reroutes and alternative routes. In general, once a preliminary design is developed, a survey crew must survey the new facilities, construction personnel must visit the site and verify the preliminary design is feasible, then biological, cultural, and hydrological resources are surveyed and assessed. In the end, an average of five separate disciplines and contractors must get involved for a design change. Reducing the design detail to what is required by CEQA to allow a meaningful evaluation of potentially significant impacts and alternatives that may reduce them will save time and expense.

Eighth, SDG&E raises the question of whether the pre-filing requirements are serving their intended purpose. From SDG&E's standpoint, the pre-filing consultations are meant to ensure that SDG&E's PEA meets ED's needs for completing an appropriate CEQA document. SDG&E strives to ensure that the PEA is complete for that purpose so that ED can begin and promptly complete its CEQA review. However, sometimes SDG&E believes that the PEA contains all of the CPUC PEA Checklist items and is still deemed deficient. Even when a PEA is deemed complete relatively soon after filing, ED tends to issue numerous data requests over many months, delaying completion of the CEQA process. This occurs even when all of the CPUC PEA Checklist items have been provided. If the pre-filing consultation process is not achieving its objective of ensuring a complete PEA, perhaps the benefits are not worth the additional time it takes.

SDG&E looks forward to engaging with ED on these issues.

QUESTION 2

Please answer the following questions regarding application filing and pre-filing review:

a. Once a project is approved by CAISO, should the CPUC require the project proponent to file an application within a specified time window after CAISO approval (e.g., within one year) or within a specified time window prior to the required or forecasted in-service date (e.g., two years prior to the in-service date)? Alternatively, is it feasible to institute different filing deadlines based on project type and complexity? Please explain.
b. Are there modifications to the pre-filing review process or application process that would incentivize applicants to initiate pre-filing consultation with the CPUC earlier in the project design process? Please explain.
c. Are there other modifications to GO 131-D that could enable applicants to provide project information (e.g., in-service date, project objective and design, potentially feasible siting/routing) to the CPUC on an expedited basis for CAISO-approved projects, or that could otherwise enable the CPUC to begin environmental review sooner? To what extent can this information be provided prior to application filing via the Transmission Project Review (TPR) Process or via existing recurring meetings between IOUs and CPUC staff? Please explain.

SDG&E RESPONSE 2a

Each project that is approved by the CAISO is unique in its complexity, and a specified application timeline post approval would not be appropriate given the differences in desired in-service date, scope, habitat, communities, terrain, and the various other factors that need to be examined under CEQA for large transmission projects. For example, two projects may be very similar in scope, but one crosses previously disturbed terrain, reducing or eliminating the need for biological, cultural, and paleo surveys, where the other project may require all three. As noted above in response to Question 1.b, biological surveys for a single species can extend over a year's time. The coordination with landowners, seasonality of species, and other complexities will drive the timeline to assess and perform the necessary surveys to give the Commission the appropriate level of detail to do a comprehensive CEQA analysis of the project (or for SDG&E to prepare a draft CEQA document, as proposed in the Settlement Agreement in this proceeding). Fundamentally, to prepare a CPCN or PTC application for a specific project, SDG&E must undertake the tasks outlined in SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-001, Question 1A. Setting a deadline will not alter the tasks that must be completed or the time required to complete such tasks.

Similarly, attempting to set a filing deadline a certain number of years before the desired in-service date presents its own set of issues. As an initial matter, project construction is not a simple cookie cutter affair. More complex projects have constraints that will impact the construction timeline in non-linear ways: a certain species may require construction to occur only during certain times of year, and those windows may present concerns with outage coordination, traffic permits, etc. Moreover, without significant reforms in Commission processing of CPCN and PTC applications, it is impossible to predict how many years it may take for the Commission to approve a filed application, and thus how many years before a desired in-service date a filing deadline should be set. Further, as noted above, SDG&E must undertake the tasks outlined in SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-001, Question 1A. Setting a deadline will not alter the tasks that must be completed or the time required to complete such tasks. Setting an application timeline based on the in-service date will likely lead to missed in-service dates for projects that don't fit neatly into a pre-defined box.

SDG&E RESPONSE 2b

The IOUs currently communicate project status (including pre-filing stage) of transmission projects to the Commission on a quarterly basis. These meetings provide an opportunity for the Commission to ask questions regarding the project, including any schedule concerns about application filing.

As set forth in response to Question 1.e above, application filing could be accelerated if Energy Division were able and willing to determine that a Mitigated Negative Declaration is likely appropriate early in the IOU environmental review process, and thus negate the need to prepare a full PEA. If an earlier pre-filing review process resulted in fewer deficiency notices and an elimination of post-filing Energy Division data requests, it could serve a useful purpose.

SDG&E RESPONSE 2c

Modifications to GO 131-D are not required for the Commission to learn considerable information about CAISO-approved projects as the CAISO Transmission Plans provide such information, including desired in-service date and project objectives. The CAISO Transmission Plans do not address siting or routing of CAISO-approved projects, but assessing and proposing the siting or routing of such projects requires the iterative engineering, land rights and environmental work described in SDG&E's response to CPUC Data Request CPUC-SDGE-TPP-

001, Question 1A. There is no point in SDG&E informing Energy Division about every potential site or route considered before SDG&E has considered its technical feasibility, constructability, available land rights, and potential environmental impacts, any of which may quickly eliminate such a site or route. Fundamentally, SDG&E must complete each unique project's engineering, land rights and environmental review before it can file a CPCN or PTC application, and most of that work needs to be completed before SDG&E can have a useful discussion with Energy Division staff regarding the proposed project. For that reason, streamlining Energy Division's review process is the best opportunity to expedite Commission decisions on electric transmission projects.

If the CPUC could contract with its environmental consultants earlier, that also likely would expedite environmental review.

QUESTION 3

Please answer the following questions regarding the provision of cost estimates:

a. Please explain in detail the point in your internal planning process at which cost estimates are typically submitted to the CPUC, when required. What actions are required for applicants to provide an estimated cost for PTC projects and a statement of why the project is needed? What challenges or barriers do applicants encounter during this process? Can they be addressed by the Commission, and if so, in what ways can they be addressed?
b. Would showing that a project was selected as a result of a competitive process at the CAISO, which includes a cost cap, satisfy requirements to demonstrate the cost and need for CPCN and PTC projects?
c. To what extent are any delays in the provision of cost estimates attributable to the design and planning of interconnection to the distribution system? Please explain and provide examples.
d. Please also explain the typical time periods for cost estimates to reach different levels of reliability (e.g., 100% contingency, 50% contingency, 25% contingency), and what factors may impact these time periods.
e. When and why do costs submitted to the CPUC in the application process differ from costs identified in the CAISO Transmission Plan? Please provide a range of examples of such projects and explain what caused the difference.

Date Received: January 29, 2024
Date Submitted: March 8, 2024

SDG&E RESPONSE 3a

Pursuant to the Commission decisions, as well as GO 131-D itself, a project requiring a PTC does not require submittal of cost information, nor a description of need. GO 131-D, both before and as amended by D.23-12-035, provides: "The above information requirements notwithstanding, 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." As stated in the 1994 Decision 94-06-014 adopting GO 131-D, under the PTC process "our review focuses solely on environmental concerns, unlike the CPCN process which considers the need for and economic cost of a proposed facility." 1994 Cal. PUC LEXIS 453 *2.

Pursuant to Senate Bill (SB) 529, codified at Public Utilities Code Section 564, the Commission may not require an electric public utility seeking "approval to construct an extension, expansion, upgrade, or other modification to its existing electrical transmission facilities" to provide a detailed analysis of purpose or necessity or a detailed estimate of costs. SB 529 specifically authorizes public utilities to "use the permit to construct process … under that general order," *i.e.*, GO 131-D, and as set forth above that process did not include providing such information. The Legislature was specifically aware that the PTC process did not include such information. *See, e.g.*, Senate Third Reading: SB 529 As Amended August 23, 2022 ("the PTC process, generally does not require a detailed analysis of the need for nor the economics of a project"). The Legislature's intent to expedite transmission projects by making the PTC process available to projects that would otherwise require a CPCN would be utterly frustrated if the Commission attempted to change the PTC process to impose the CPCN cost and need requirements.

SDG&E has not encountered challenges or barriers to providing a high level, non-detailed cost estimate for PTC projects or a brief summary of the need for the project, as required by GO 131-D.

SDG&E RESPONSE 3b

As set forth in response to Question 3.a above, GO 131-D does not require a showing of cost or need for PTC projects. Further, pursuant to Assembly Bill (AB) 1373 (2023), Section 10, codified at Public Utilities Code Section 1001.1: "In a proceeding evaluating the issuance of a certificate of public convenience and necessity for a proposed transmission project, the commission shall establish a rebuttable presumption with regard to need for the proposed transmission project in favor of an Independent System Operator governing board-approved need evaluation" if certain conditions are met. SDG&E anticipates that most, if not all, CAISO-approved transmission projects required to file a CPCN application will establish need through such rebuttable presumption. Notably, projects subject to CAISO's competitive bidding process are already subject to oversight at FERC with respect to any overages above the established cost cap. A selected project sponsor in a CAISO competitive bid process enters into a contractual agreement with the CAISO where the project sponsor agrees to abide by the cost cap included as part of the bid. When a project sponsor puts a project into service and into its FERC-jurisdictional rates, a process exists at FERC to validate any overages above the capped costs. *See* ER23-2309.[1]

SDG&E RESPONSE 3c

While the cost estimates for transmission projects can include distribution costs (such as distribution underbuilt on a transmission pole or substation expansions/relocations for example), the estimation of such costs is not typically a driving factor behind the timelines needed to develop cost estimates for transmission projects.

SDG&E RESPONSE 3d

There are no firm timelines for the cost estimates to reach defined levels of reliability, as the amount of contingency included in an estimate is driven by the amount of information known about a project. As the elements of the project come into focus (location, design details, etc) the amount of contingency carried in the cost estimate can be reduced. In some instances, the project estimate can be refined early, such as in an equipment replacement project within a substation. Once purchase prices are obtained, and the need for any additional work assessed, the project estimate can have contingency reduced significantly. For more complex projects, contingency may remain high for most of the project life cycle. For example, projects that require a PTC or CPCN go through a very rigorous environmental review process, in which the scope and location of the project can change significantly from the project that SDG&E originally proposed in its application. In these instances, it is appropriate to carry a higher

[1] Available at https://elibrary.ferc.gov/eLibrary/search.

contingency amount until the final approval of the application, and along with it, the project details that are necessary to reduce contingency.

SDG&E RESPONSE 3e

Costs included in the CAISO Transmission Plan are typically conceptual cost estimates built from a unit cost template – i.e., cost per mile of transmission line, cost per transformer/circuit breaker, etc. These costs do not typically take into account the real-world constraints of land use, supply chain, permitting, etc. These constraints will have significant impact on the ultimate cost of the project, but cannot be known at the time that the Plan is issued by the CAISO. The costs included in the TPP are developed by the IOUs at the request of the CAISO, who uses them as part of their analysis for comparison purposes between different alternatives. The IOUs are typically given a short window to develop the cost estimate, as the CAISO is primarily interested in performing alternatives analysis, comparing projects against one another. For this purpose, project feasibility studies are not performed, as SDG&E has no way to know which project will be carried forward in the CAISO's analysis.

QUESTION 4

Please answer the following questions regarding the CPCN and PTC exemption criteria:

a. Would adding specificity to the CPCN and PTC exemption criteria (e.g., including a non-exhaustive list of examples of "equivalent facilities or structures", "minor relocation", and "accessories") increase applicant certainty regarding whether an exemption would apply and/or increase the number of projects for which an exemption may apply? If so, please provide specific suggestions (e.g., converting existing lattice towers or wood poles to steel monopoles no more than X percent taller than the existing structures). If additional terms are proposed, please provide definitions.
b. Would adding specificity to the term "minor relocation of existing power line facilities" in Section III.A (for CPCN exemptions) increase advice letter filings and reduce application filings (e.g., by increasing the number of projects that are eligible for PTC exemptions 1b, 1c, and 1e)? Please explain.
c. Would reformatting the CPCN exemptions in GO 131-D Section III.A as an ordered list, similar to the existing list of PTC exemptions in Section III.B.1, increase applicant certainty regarding whether an exemption would apply?
d. Are there any other pros and cons to making such modifications? Please explain.

<u>SDG&E RESPONSE 4a</u>

SDG&E does not believe that efforts to add specificity to such terms through a non-exhaustive list of examples would increase certainty or expedite projects. SDG&E has worked with Energy Division to understand and apply the CPCN and PTC exemptions since 1994. Some projects clearly fall within such exemptions and others require discussion with Energy Division based upon their unique attributes. A non-exhaustive list would not change that process. SDG&E also does not believe the CPUC should attempt to create an exhaustive list, as that would reduce flexibility in addressing unique projects.

<u>SDG&E RESPONSE 4b</u>

See Response 4a above which also applies to adding specificity to the term "minor relocations...."

<u>SDG&E RESPONSE 4c</u>

No. SDG&E understands the current format.

<u>SDG&E RESPONSE 4d</u>

Efforts to identify a non-exhaustive list of the type of projects that qualify for each exemption appears likely to result in considerable debate about the examples, Commission past practice, and various parties' policy preferences. Given that such a list would be non-exhaustive, which is appropriate given the many variations of unique projects that might be pursued in the future, engaging in such litigation does not appear to be a good use of the Commission's or the parties' time and resources.

QUESTION 5

What are the current typical lead times for obtaining equipment critically necessary to complete transmission projects (such as transformers, circuit breakers, busbars, conductors, etc.)? What factors influence the calculation of estimated lead times? Are there any emerging issues (e.g., supply chain) that will significantly impact future lead times? What actions can transmission developers take to expedite timelines for obtaining equipment? Could explicit authorization to procure long-lead-time equipment expedite transmission projects?

SDG&E RESPONSE 5

Transmission lead times vary depending on the equipment required for the work. The longest lead times can range from 28 weeks for steel poles to 50 weeks for Conductor/Cable equipment. Major substation equipment lead times also vary by equipment type. For example, circuit breakers range from 45 weeks (12kV CB) to 320 weeks (500kV CB) and power transformers have a lead time of 104 weeks. The estimates for the lead times are a mix of historical estimates, contractual terms with the vendor, or factory reservations that are committed to SDG&E.

Supply chain disruptions have impacted the lead times of our equipment and materials. We have observed vendors pushing out delivery dates due to many factors, including raw material shortages, workforce challenges or retention issues, change of ownership, and shipment challenges. The best way to mitigate the risk of delays is for transmission developers to reserve and commit to buying poles years before the poles are needed. This allows the pole manufacturer to schedule in the time upfront and get ahead of any issues. Qualifying multiple manufacturers may mitigate the risk of delays, but does not allow the opportunity to reduce lead times. There may be limited opportunities to order material earlier in the process with explicit authorization. The project's scope would have to be narrowed to one of the proposed alternatives or all alternatives would have to have a common element.

QUESTION 6

Of all the transmission projects approved by CAISO in the past five years, is there a subset of projects that should be prioritized (e.g., policy-driven transmission projects) for California to reach its emission reduction goals? Please explain.

a. Would prioritizing these projects help streamline permitting? If so, can this be accomplished by changes to GO 131-D in Phase 2 of this proceeding?

b. To what extent could more detailed project routing and siting work coupled with feasibility studies and high-level environmental constraint analyses conducted up front during the CAISO transmission project identification and planning processes streamline subsequent State siting approvals?
c. Are there other changes to the electric transmission planning and permitting process that would be necessary to achieve State emission reduction goals, e.g., new legislation or changes to GO 96-B? Please describe any recommended changes in detail.
d. More broadly, is there an optimal way to sequence the build-out of the grid? Are there workforce or supply chain constraints that prevent projects from being constructed simultaneously?

SDG&E RESPONSE 6a

SDG&E would be concerned if CAISO-approved policy-driven projects are prioritized ahead of CAISO-approved reliability-driven or economic-driven projects, which are also important projects. Policy-driven projects are focused on interconnecting zero-carbon resources of the grid while reliability-driven projects are required to facilitate electrification plans (e.g., EV, hydrogen production, fuel substation, etc.). SDG&E notes that both decarbonization and electrification at equally important state goals.

The project proponents (IOUs, third party developers) prioritize the projects in their portfolio based on the complexity, resource constraints, and in service dates of the projects. CAISO's TPP prioritizes projects by assessing when such projects are needed in light of the CPUC's resource portfolio and the CEC's load forecasts. SDG&E does not believe that adding an additional prioritization process at the CPUC would expedite projects, but rather believes that it would divert utility resources from performing the work necessary to move forward on its transmission projects.

SDG&E does not believe that the challenge with timely building TPP projects is a prioritization issue, but rather is a permitting process issue. The Commission could help by expediting the implementation of SB 529, AB 1373, and by promptly adopting the proposed revisions to GO 131-D set forth in the Settlement Agreement presented by the Joint Motion for Adoption of Phase 1 Settlement Agreement ("Joint Motion") that were not addressed in the Phase 1 Decision.

SDG&E RESPONSE 6b

While the CAISO excels at planning and operating the California transmission system, it does not have experience or expertise when it comes to routing, siting, and conducting the various types of analyses required for a CEQA review. Attempting to integrate this type of analysis into the CAISO planning process would simply slow CAISO down, introducing further delays. The IOUs and third-party developers are best suited to identifying locations and routes, as well as performing the environmental analysis needed to fully analyze and approve a large transmission project. This leaves the CAISO free to focus its expertise in performing the critical analysis of system needs which are imperative in meeting California's climate goals.

If Question 6b is asking whether SDG&E believes it would be useful for SDG&E to perform such work before CAISO has identified and approved transmission projects, the answer is no. Attempting to perform feasibility and environmental studies for every possibility that the CAISO might consider would be an enormous strain on resources, adding to ratepayer costs, even assuming that SDG&E were able to learn what options the CAISO is considering.

SDG&E RESPONSE 6c

The most effective changes to the permitting process that are necessary to achieve State emission reduction goals are set forth in the Settlement Agreement submitted in this proceeding by the September 29, 2023 Joint Motion for Adoption of Phase 1 Settlement Agreement ("Joint Motion"). As set forth therein, the proposed revisions to GO 131-D would:

- Authorize applicants to submit a "Draft CEQA Document" in lieu of a PEA for the Commission's independent review and analysis, circulation for public review, and finalization, all consistent with CEQA Guidelines § 15084(d). This revision would obviate the duplicative, time-consuming and expensive process whereby Commission staff and retained consultants preparing CEQA documents essentially re-write the entire environmental analysis already contained in the PEA.
- Recognize CAISO transmission planning findings in the Commission's consideration of CPCN or PTC applications, including in analysis of certain CEQA issues. These revisions would avoid the time and expense of duplicating the extensive transmission system planning performed by CAISO, in close coordination with the Commission and the California Energy Commission ("CEC"), pursuant to California law and its FERC-approved

tariff. Moreover, recognition of CAISO "need" determinations is required by AB 1373 in most cases.

- Set deadlines for the Commission's CEQA and permitting process to ensure that the potential time savings from authorizing applicant-prepared Draft CEQA Documents and recognizing CAISO's transmission planning findings are realized. While the proposed deadlines are aggressive, the Legislature found such deadlines reasonable when it enacted AB 205, adopting the same timing deadlines for the CEC's consideration of certain infrastructure projects.
- Confirm procedures for filing, processing and disposition of protests filed under GO 131-D so that transmission projects are not delayed by protests that lack any valid reason to negate a claimed permitting exemption. As recognized in GO 131-D itself, some protests are properly resolved by the Executive Director and do not require a Commission vote.

For additional proposals to streamline the CPUC permitting process, *see* Opening Comments Of San Diego Gas & Electric Company (U 902 E) On Phase 2 and the response to Question 1.e above.

SDG&E RESPONSE 6d

SDG&E does not believe there is one "optimal" way to build out the transmission grid. Each year new transmission projects are identified, and these new projects will be woven into the workstream of existing projects, in some cases taking advantage of efficiencies to complete the work in parallel, in other cases slotted in a serial queue due to various constraints. While workforce and supply chain issues exist, there is no reliable way to predict which (if any) constraints will affect a particular project.

QUESTION 7

In the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023, settling parties proposed adding "power line facilities or substations" to the second clause of section III.B.1.g. Of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, how many are located within a "utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies"? Please provide a list of these projects and the applicable utility corridor(s). Of these projects, how many currently qualify for exemption "g", and how many would qualify for exemption "g" if the settlement agreement suggestion were to be implemented? Do the parties anticipate other, future utility corridors that would impact the use of exemption "g"? Please explain.

SDG&E RESPONSE 7

The Settlement Agreement proposed to revise GO 131-D, Section III.B.1(g) as shown in the underlined text as follows:

> power line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility right of way (ROW) or easement; or power line facilities or substations in a utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies for which a final Negative Declaration or EIR, Mitigated Negative Declaration, or Environmental Impact Report (EIR) finds no significant unavoidable environmental impacts.

The Settlement Agreement proposed to add the words "power line facilities or substations" to the second clause following the semi-colon for grammatical reasons—to make plain that subject of the second clause is "power line facilities or substations." Upon further review, the proposed revision would be better written as "power line facilities or substations to be located …." This obviously was the Commission's intent in adopting GO 131-D in 1994 as the second clause applies to facilities to be located in such a designated "utility corridor." Thus, the addition of the words "power line facilities or substations" simply corrects the grammar to make its meaning clear.

The Energy Division's first specific question is: "Of the transmission projects above 50 kV that were approved in the last five CAISO TPPs, how many are located within a 'utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, State, or local agencies'" for which a final Negative Declaration or EIR finds no significant unavoidable environmental impacts? For projects that were either assigned to SDG&E or for which SDG&E was awarded the project following competitive bidding, the answer is none.

Question 7 then asks: "Of these projects, how many currently qualify for exemption 'g', and how many would qualify for exemption 'g' if the settlement agreement suggestion were to be implemented?" As noted above, no projects assigned to SDG&E or awarded to SDG&E following competitive bidding qualify for exemption under the second clause of exemption "g." Because the proposed revision merely corrects a grammatical error, and does not change the meaning of exemption "g," adoption of the Settlement Agreement's proposed revision to add "power line facilities or substations" to the second clause would not change whether a project is subject to exemption "g."

Question 7 asks: "Do the parties anticipate other, future utility corridors that would impact the use of exemption 'g'?" There have been and are proactive efforts to identify utility corridors and thus expedite environmental review. For example, Public Resources Code § 25330 *et seq.* establishes a process for the Energy Commission to designate transmission corridor zones for high-voltage electric transmission lines following CEQA review, and afterward identify such zones in strategic plans.[2] While it is speculative where such utility corridors may be established and whether such corridors will be useful for future needed transmission lines, future use of the second clause of exemption "g" for certain projects is possible. As the Commission stated in adopting GO 131-D's exemption "g": "We believe that it is appropriate to provide an exemption for projects that are to be constructed within franchises, approved corridors, or in connection with broader actions that have been approved in accordance with CEQA. Once a government agency has reviewed the placement of utility facilities pursuant to CEQA, we see no reason for the Commission to duplicate that effort." 1994 Cal. PUC LEXIS 453 at *47-49. The Settlement Agreement proposed revision simply clarifies the Commission's intent to avoid any confusion.

QUESTION 8

Please explain whether the proposals in the Joint Motion for Adoption of Phase 1 Settlement Agreement filed by SCE, PG&E, and SDG&E on September 29, 2023 are consistent with the following provision of GO 131-D or whether this provision should be amended: "For all issues relating to the siting, design, and construction of electric generating plant or transmission lines as defined in Sections VIII and IX.A herein or electric power lines or substations as defined in Section IX.B herein, the Commission will be the Lead Agency under CEQA, unless a different designation has been negotiated between the Commission and another state agency consistent with CEQA Guidelines § 15051(d)."

[2] Pub. Res. Code §§ 25330, 25331, 25332, 25339.

SDG&E RESPONSE 8

The Settlement Agreement's proposed revisions to GO 131-D are consistent with the quoted portion of GO 131-D, Section XVI. However, just as Decision 23-12-035 (the "Phase 1 Decision") amended Sections IX.A, IX.B and XI.A to refer to facilities that either "require a CPCN under Section III.A, above" or "require a permit to construct under Section III.B, above," it would be better to amend the final sentence of Section XVI as proposed in the Settlement Agreement to read: "For all issues relating to the siting, design, and construction of electric generating plant or transmission lines ~~as defined in Sections VIII and IX.A~~ requiring a CPCN under Section III.A herein (except as set forth in Section VII herein) or electric power lines or substations ~~as defined in~~ requiring a PTC under Section ~~IX~~III.B herein, the Commission will be the Lead Agency under CEQA, unless a different designation has been negotiated between the Commission and another state agency consistent with CEQA Guidelines§ 1505l(d)." (red font shows proposed additions).

Nothing in the Settlement Agreement changes the Commission's role as Lead Agency under CEQA for electric projects requiring either a CPCN or PTC under GO 131-D. The Settlement Agreement proposed revision to allow a public utility to submit, with its application for a PTC or CPCN, a draft CEQA document or information justifying a CEQA exemption instead of a Proponent's Environmental Assessment ("PEA") is directly authorized by CEQA Guidelines § 15084(d), which provides that a lead agency may "choose one of the following arrangements or a combination of them for preparing a draft EIR … (3) Accepting a draft prepared by the applicant, a consultant retained by the applicant, or any other person." The Lead Agency's continuing role is required by CEQA Guidelines § 15084(e), which provides, "Before using a draft prepared by another person, the Lead Agency shall subject the draft to the agency's own review and analysis. The draft EIR which is sent out for public review must reflect the independent judgment of the Lead Agency."

If Energy Division believes that the Settlement Agreement is inconsistent with the quoted sentence in GO 131-D, Section XVI, SDG&E requests that Energy Division explain its concern.

QUESTION 9

How should the ability of non-wire alternatives and distributed energy resources to meet project objectives be evaluated? Should the CPUC still pursue the deferral of distribution upgrades through the use of distributed energy resources? What is CAISO's current process for reporting on the feasibility of non-wire transmission alternatives (and can this process be improved to provide the CPUC with information that better informs the CEQA process)? How are distribution-level non-wire alternatives considered by an applicant prior to application submittal? What opportunities could the CPUC pursue to streamline review of non-wire distribution-level alternatives, and should the CPUC pursue this issue?

SDG&E RESPONSE 9

- **How should the ability of non-wire alternatives and distributed energy resources to meet project objectives be evaluated?**

  Non-wires alternatives to new transmission, including distributed energy resources, are considered by the CAISO as part of its annual Transmission Planning Process (TPP).[3] The CAISO recently addressed claims that its TPP does not consider non-wires alternatives in its Reply Comments Of The California Independent System Operator Corporation On Joint Motion For Adoption Of Phase 1 Settlement Agreement at 4 (footnotes omitted):

[3] See, for example,
- section 24.2(d): "The Transmission Planning Process shall… identify transmission upgrades and additions, including alternatives thereto, deemed needed to address the existing and projected limitations;"
- section 24.3.1(j) "The CAISO will consider the following in the development of the Unified Planning Assumptions and Study Plan: … Generation and other non-transmission alternatives that are proposed for inclusion in long-term planning studies as alternatives to transmission additions or upgrades;"
- section 24.3.3: "…parties may submit the following proposals for consideration in the development of the draft Unified Planning Assumptions and Study Plan: (i) Demand response programs for inclusion in the base case or assumptions; (ii) Generation and other non-transmission alternatives, consistent with Section 24.3.2(a) proposed as alternatives to transmission solutions;"
- section 24.4.3(a): "the CAISO will open a Request Window…for the submission of…demand response or generation proposed as alternatives to transmission additions;"
- section 24.4.5 "To determine which transmission solutions should be included in the comprehensive Transmission Plan, the CAISO will evaluate the conceptual transmission facilities identified by the CAISO… and will consider potential transmission solutions and non-transmission or generation alternatives proposed by interested parties;"
- section 24.4.6.2: "The CAISO…will, as part of the Transmission Planning Process…identify the need for any transmission solutions required to ensure System Reliability….In making this determination, the CAISO…shall consider lower cost solutions, such as…Demand-side management,…, appropriate Generation, interruptible Loads, storage facilities…;"
- section 24.4.6.7(d): "…the CAISO will conduct the…studies that the CAISO concludes are necessary to determine whether additional transmission solutions are necessary….in determining whether a particular solution is needed, shall also consider the comparative costs and benefits of viable alternatives to the particular transmission solution, including: … non-transmission solutions, including demand-side management."

> Additionally, the CAISO seeks to address misinformation about the CAISO's TPP process. Some parties incorrectly state that the CAISO's TPP does not consider non-transmission alternatives. As the CAISO has explained in prior comments, the TPP process does consider non-transmission alternatives. Other parties state that the CAISO's tariff requirements are inadequate because non-wires alternatives are included only when proposed by stakeholders. The CAISO does unilaterally consider storage on the transmission system, for example. Ultimately, if stakeholders seek to include distributed energy resources and other nonwires alternatives in the analysis that could impact the CAISO's decision-making, the appropriate venue to adequately model and study those solutions is in the CAISO's planning process and not in a process intended to evaluate and mitigate environmental impacts. Stakeholders have the opportunity to engage early in the evaluation of all electrical solutions and should not rely on the CEQA process to re-litigate findings made in the CAISO's TPP. Such intervention only at the CEQA phase of a transmission project's development misses crucial opportunities to engage during the electrical modeling phase of the process and can serve as a delay to the evaluation.

Accordingly, to the extent it is determined that the Commission is obliged to consider non-wires alternatives in a CEQA analysis, SDG&E recommends the Commission defer to the CAISO's determination that the transmission approved through the CAISO's TPP is superior to the non-wires alternatives considered by the CAISO. This will maintain consistency in the CAISO's and CPUC's consideration of need for new transmission, minimize or eliminate the need for the CPUC to conduct a separate assessment of non-wires alternatives, and help to streamline the CPUC's transmission licensing processes during a period when timely infrastructure upgrades are key to meeting the state's climate goals.

SDG&E notes that the Commission requires that the Integrated Resource Plan (IRP) proceeding incorporate the California Energy Commission's (CEC's) adopted forecast of Behind-The-Meter (BTM) Distributed Energy Resource (DER) impacts on metered electric load. The resource portfolio and associated high-level transmission needs which emerge from the IRP proceeding therefore reflect the impact of DERs. Since, pursuant to the December 2022 Memorandum of Understanding between the Commission, the CEC and the CAISO; the CAISO uses the IRP results in the CAISO's TPP; specific transmission upgrades approved through the TPP have already accounted for forecast DER impacts. It is not efficient or necessary for the Commission to reconsider the impact of DERs on CAISO approved transmission upgrades.

The Settlement Agreement proposes adding Section IX.C.2(c) to GO 131-D that would establish "a rebuttable presumption that the consideration of cost-effective alternatives to transmission facilities required by Public Utilities Code Section 1002.3, if applicable, may be limited to the analysis of such alternatives to the proposed project as set forth in the relevant CAISO Transmission Plan and the base resource portfolio provided by the Commission to CAISO for development of that Transmission Plan." Absent unusual circumstances, the Commission's CEQA analysis for a specific project is not an appropriate place to re-visit the analysis underlying the Commission's IRP resource portfolio, the CEC's load forecast, and the CAISO's consideration of cost-effective non-wires alternatives. The existing process ensures that non-wires alternatives and DERs are considered with respect to transmission projects.

- **Should the CPUC still pursue the deferral of distribution upgrades through the use of distributed energy resources?**

The nexus between the licensing of transmission under GO 131-D and the deferral of distribution upgrades is unclear from the question posed. GO 131-D, Section III.C provides:

> "The construction of electric distribution (under 50 kV) line facilities … does not require the issuance of a CPCN or permit by this Commission nor discretionary permits or approvals by local governments."

Neither the OIR 23-05-018 nor either Scoping Memo suggests that the Commission is considering a change to this provision. Therefore, SDG&E does not understand how this question is within the scope of this proceeding or how it relates to GO 131-D. Generally, as noted above, SDG&E understands the Commission to anticipate and encourage DERs, which will reduce electric loads (and possibly add supply), which may defer or avoid distribution upgrades. Similar to how the CAISO's TPP accounts for forecast BTM DER impacts on metered load, the Commission requires that the utilities' Distribution Planning Processes (DPPs) incorporate the CEC's forecast of BTM DER impacts on metered load. Thus, the impact of forecast BTM DERs on the need for distribution upgrades is already accounted for.

SDG&E believes that in certain circumstances incremental DERs – in the right place, in the right amount and with the right operating characteristics-- can be viable cost-effective alternatives for deferring planned distribution upgrades. To ensure that ratepayers get the maximum benefit from such deferral, the existing competitive Request For Offer (RFO) solicitation process should be maintained as the deferral mechanism. The competitive RFO solicitation process allows both In-Front-of-the-Meter (IFM) and incremental BTM DERs to compete to defer planned distribution upgrades.

The first two cycles of the Partnership Pilot deferral process, however, have clearly demonstrated that BTM distributed energy resources are rarely a practical or cost-effective alternative for deferring planned distribution infrastructure. Unless cycle 3 of the Partnership Pilot provides materially different results, there is good reason to believe that the Commission will off-ramp the Partnership Pilot prior to the start of a cycle 4. The Standard Offer Contract (SOC) pilot, which provided a mechanism by which In-Front-of-the-Meter (IFM) DERs could defer planned distribution upgrades, has already been cancelled given that the pilot resulted in no cost-effective deferral of planned distribution upgrades.

- **What is CAISO's current process for reporting on the feasibility of non-wire transmission alternatives (and can this process be improved to provide the CPUC with information that better informs the CEQA process)?**

The Energy Division should contact the CAISO directly for a response to this question. As noted in SDG&E's response to the first sub-question above, SDG&E recommends that the CPUC defer to the CAISO's determination that non-wires alternatives are not superior to the new transmission approved through the CAISO's TPP. SDG&E also notes that the CPUC can and does participate in the CAISO's annual TPP where non-wires alternatives are considered.

As explained in the Joint Motion for Adoption of Phase 1 Settlement Agreement at 28-37 and the Joint Reply Comments On Joint Motion For Adoption Of Phase 1 Settlement Agreement at 23-26, 29-30, the Commission, the CEC and the CAISO coordinate on electric load forecasting, resource planning and transmission planning to achieve state reliability and policy goals.[4] The "CAISO utilizes resource portfolios from the Commission's Integrated Resource Plan (IRP) proceeding in order to identify needed transmission projects."[5] As recognized in a December 2022 Memorandum of Understanding among the Commission, the CEC and CAISO, the CAISO conducts electric transmission planning to meet the electricity transmission needs for the loads and resources identified by the Commission in response to the CEC's electric load forecasts.[6]

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[4] See, e.g., CAISO 2022-2023 Transmission Plan, https://www.caiso.com/Documents/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf ("CAISO 2022 TP") at 11-17.

[5] Opening Comments of The California Independent System Operator Corporation (CAISO Comments) at 1.

[6] SDG&E Comments at 40 (citing https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/iso-cec_cpuc-memorandum-of-understanding_202212.pdf (MOU at 2-3, Paragraphs 3-7).

In developing its IRP resource portfolios and associated high-level transmission needs, the Commission considers energy efficiency, demand-side programs and DERs.[7] The Commission then provides this portfolio to CAISO for use in its TPP.[8] In the TPP, the CAISO evaluates the feasibility of incremental DERs (preferred resources) to offset identified transmission needs or solve identified transmission system constraints.[9,10] For example, the CAISO 2022 Study Plan includes Sections 2.6.4 (Self-Generation), 2.7.7 (Distribution Connected Resources Modeling Assumption), and 2.8 (Preferred Resources). Third, CAISO determines whether such preferred resources are an alternative to specific transmission projects to solve specific system constraints.

SDG&E recognizes that the Commission expects a "high DER future" and is evaluating how to optimize integration of DERs to better utilize both their generation and storage potential.[11] As the Commission resolves these issues, and when integrated DERs

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[7] *See, e.g.*, R.22-11-013 at 4, n.5 ("Energy efficiency, residential photovoltaics (PV), certain demand response resources, and other DERs are included in the IRP via the demand forecast process. Also, some DERs are incorporated in IRP modeling as 'candidate resources' that can be selected to meet future grid needs."); Pub. Util. Code § 454.51 (as amended by Assembly Bill (AB) 1373, Section 7 (Garcia 2023)) ("The commission shall … (a) Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy and resource diversity in a cost-effective manner.").

[8] *See, e.g.*, CAISO 2022 TP at 2 n. 5 ("Each year, the CPUC provides a base resource portfolio, that the ISO is expected to use in determining the need for new transmission projects.").

[9] CAISO 2022 Study Plan at Section 2.8.1 ("As in the previous planning cycles, reliability assessments in the current planning cycle will consider a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies will also incorporate the incremental uncommitted energy efficiency and fuel substitution amounts as projected by the CEC and a mix of preferred resources including energy storage based on the CPUC authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation that is embedded in the CEC load forecast.")

[10] Examples of this analysis are found in the CAISO 2022 TP, Appendix B: Reliability Assessment, which is contains confidential information and is subject to a non-disclosure agreement. Appendix B includes information about the modeling assumptions for such preferred resources in Sections B.1.3.3 (including energy efficiency and self generation), and B.1.3.5 (preferred resources, energy storage and demand response). Further, Appendix B includes CAISO's assessment of particular reliability constraints and how to fix them, which include sections entitled "Consideration of Preferred Resources and Energy Storage" that analyze whether preferred resources can resolve the constraint.

[11] See *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* (R.21-06-017); *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates* (R.22-07-005); and *Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Use And Access, And Equipment Performance Standards* (R.22-11-013).

become an available resource, the Commission intends to more completely include them in its IRP resource portfolio that underlies CAISO's transmission planning.[12]

- **How are distribution-level non-wire alternatives considered by an applicant prior to application submittal?**

  As indicated in SDG&E's response to the first sub-question, the CAISO considers non-wires alternatives in its annual TPP. Therefore, the new transmission approved through the TPP, and for which an applicant is seeking a permit from the CPUC to construct, has already been tested against non-wires alternatives, including those at the distribution-level. It is the responsibility of the CAISO under its tariff, not the applicant before the CPUC, to consider non-wires alternatives to transmission projects.

  With respect to transmission projects that are not reviewed and approved by the CAISO, DERs are not feasible alternatives. For example, DERs cannot eliminate the need to fire-harden existing transmission – it is not the amount of power that flows on an existing transmission line that creates a fire risk; rather, it is the exposure of the line to the surrounding elements that creates the risk. DERs cannot substitute for the replacement of aging transmission infrastructure – a failed transformer at a major substation can jeopardize reliability at multiple other substations. DERs cannot replace this critical voltage transformation capability. DERs are incapable of off-setting the need for transmission-related safety upgrades (marker balls, widening rights-of-way, improved substation security), for right-of-way payments, for environmental offset costs, for customer-requested transmission relocations, and for upgraded transmission communication and control systems.

- **What opportunities could the CPUC pursue to streamline review of non-wire distribution-level alternatives, and should the CPUC pursue this issue?**

  See SDG&E's response to the second sub-question.

[12] R.22-11-013 at p. 4 ("The IRP process is designed to guide electric utility planning, using capacity expansion and production cost modeling, to determine the least-cost path to achieving electric sector GHG reduction goals, while ensuring reliability. As of yet, DERs are not completely incorporated into IRP modeling as candidate resources. Accomplishing this will require increasing coordination amongst the various DER resource proceedings and programs and the IRP proceeding.") (footnote omitted).

Date Received: January 29, 2024
Date Submitted: March 8, 2024

QUESTION 10

Please review the generic list of permits required for a typical electric transmission project at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/g/5066-generictransmissionlinepermit.pdf. Should this list be updated? If so, please use the format in the linked table to list all the permits that are required for a typical transmission project (PTC and CPCN) from all federal and State agencies. If there are no "typical" projects, please use at least three projects as examples and list the permits required for each project.

SDG&E RESPONSE 10

SDG&E has reviewed the CPUC typical permits and does not have any specific additions to this generic list. There is considerable variability in permit applicability from project to project, location and jurisdictions involved. We have provided link references below to three recent examples for the CPUC's consideration:

Project Name	Citation	Link
Sycamore to Penasquitos 230kV Transmission Line Project	Table 3-17, page 3-61	https://ia.cpuc.ca.gov/environment/info/panoramaenv/sycamore_penasquitos/PDF/PEA_PartA.pdf
TL6975 San Marcos to Escondido	Table 3-13, page 3-42	https://ia.cpuc.ca.gov/environment/info/esa/TL6975/pdf/00_PEA_SDGE_Application_for_PTC_the_TL6975.pdf
TL TL674A Reconfiguration and TL666D Removal Project (Del Mar Reconfiguration)	Table 4-1, page 4-7	https://ia.cpuc.ca.gov/environment/info/ene/delmar/documents/4ProjectDescription.pdf

QUESTION 11

For non-IOU PTOs and independent transmission developers:

CPUC DATA REQUEST
CPUC-SDGE-GO131-001
SDG&E RESPONSE

Date Received: January 29, 2024
Date Submitted: March 8, 2024

Have any independent transmission developers experienced project delays due to actions of incumbent utilities that they were competing against in a CAISO competitive bidding process? Please explain the circumstances and any actions the CPUC could take to streamline utility processes relating to such delays.

SDG&E RESPONSE 11

This question is not applicable to SDG&E.

END OF REQUEST

(END OF ATTACHMENT A)